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INNOVATIVE CLEAN COAL TECHNOLOGY (ICCT)

Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxide (NO_x) Emission from High-Sulfur, Coal-Fired Boilers

Economic Evaluation of Commercial-Scale SCR Applications for Utility Boilers

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CONTENTS

LISTING OF FIGURES

LISTING OF TABLES

LISTING OF EXHIBITS

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EXECUTIVE SUMMARY

This report presents the results of an economic evaluation produced as part of the Innovative Clean Coal Technology project, which demonstrated selective catalytic reduction (SCR) technology for reduction of NO_X emissions from utility boilers burning U.S. high-sulfur coal. The project was sponsored by the U.S. Department of Energy (DOE), managed and cofunded by Southern Company Services, Inc., (SCS) on behalf of The Southern Company, and also cofunded by the Electric Power Research Institute (EPRI) and Ontario Hydro.

The document includes a commercial-scale capital and O&M cost evaluation of SCR technology applied to a new facility, coal-fired boiler utilizing high-sulfur, U.S. coal. The base case presented herein determines the total capital requirement, fixed and variable operating costs, and levelized costs for a new 250-MW pulverized coal utility boiler operating with a 60-percent NO_X removal. Sensitivity evaluations are included to demonstrate the variation in cost due to changes in process variables and assumptions.

This report also presents the results of a study completed by SCS to determine the cost and technical feasibility of retrofitting SCR technology to selected coal-fired generating units within the Southern electric system. While retrofit issues will vary from plant to plant and company to company, the results of this study reflect the typically wide range of retrofit costs due to site-specific issues encountered at those plants studied.

The conclusion shows the 250-MW base case unit capital and first year O&M (in 1996 dollars) are $13,415,000 ($54/kW) and $1,045,000, respectively. Levelized cost for the base case unit is $2,500/ton on a current dollar basis and $1,802/ton on a constant dollar basis. Busbar cost is 2.57 mills/kWh on a current dollar basis and 1.85 mills/kWh on a constant dollar basis.

For the new plant applications, total capital requirement for a 60 percent NO_X removal design ranged from $45/kW for a 700-MW unit to $61/kW for a 125-MW unit. Associated current dollar levelized cost ranged from $2,165/ton to $2,811/ton for the 700-MW unit and 125-MW unit, respectively.

Capital cost variation as a function of NO_X removal for a 250-MW unit ranged from $57/kW for an 80 percent design to $52/kW for a 40 percent removal design. Corresponding current dollar levelized cost ranged from $2,036/ton to $3,502/ton for the 80 percent and 40 percent removal cases, respectively.

Retrofit applications for a 60 percent removal design show a range of capital requirements from $59/kW for an 880-MW unit size to $87/kW for a 100-MW units size. There are two plants having capital requirements of $130/kW and $112/kW due to balanced draft conversion of the units. Levelized costs range from $1,848/ton to $5,108/ton on a current dollar basis.

Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxide (NO_x) Emission from High-Sulfur, Coal-Fired Boilers
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Economic Evaluation
of Commercial-Scale SCR Applications for Utility Boilers

1.0 Introduction

This report presents the results of an economic evaluation produced as part of the Innovative Clean Coal Technology project, which demonstrated selective catalytic reduction (SCR) technology for reduction of NO_X emissions from utility boilers burning U.S. high-sulfur coal. The project was sponsored by the U.S. Department of Energy (DOE), managed and cofunded by Southern Company Services, Inc., (SCS) on behalf of The Southern Company, and also cofunded by the Electric Power Research Institute (EPRI) and Ontario Hydro. Six world-wide catalyst suppliers and major equipment suppliers also participated with technical and financial contributions to the project. The project was located at Gulf Power Company's Plant Crist Unit 5 (75-MW tangentially fired boiler) located near Pensacola, Florida. The test program was conducted for approximately 2 years to evaluate catalyst deactivation and to quantify operational impacts of SCR technology employed in a high-sulfur environment. The SCR test facility included nine reactors: three 2.5-MW (large) reactors rated at approximately 5000 scfm (8500 Nm^3/hr) and six 0.2-MW (small) reactors rated at approximately 400 scfm (680 Nm^3/hr). Eight reactors operated in a hot-side, high-dust configuration while the ninth reactor operated in a hot-side, low-dust configuration. All reactors operated in parallel with commercially available SCR catalysts.

Ultimately, the goal of any test facility is to gather information and gain experience to enable a more accurate performance evaluation as well as economic analysis when extrapolated to commercial size installations. From its inception, the SCS/DOE test facility was designed to minimize the uncertainty associated with application of pilot scale test results to a full scale installation. Significant resources have been expended to present realistic costs and performance expectations of SCR technology based on the results of the 2-year test program. It is anticipated that the economic analysis presented in this report will assist interested parties with evaluating SCR compared to other possible NO_X control alternatives for future emission control requirements.

There are several regulatory and environmental drivers in various stages of consideration which may increase the likelihood of employing SCR technology in the future. Recent experience of applying SCR to new coal-fired installations has created regulatory precedent under New Source Review, which will affect future best available control technology (BACT) and lowest achievable emission rate (LAER) determinations for other new units. With one exception, these new installations are owned and/or operated by independent power producers (IPPs) who report that adopting SCR technology was necessary to quickly obtain the construction and/or operating permits.

The 1990 Clean Air Act Amendments (CAAA) mandated several NO_X control requirements and regulatory reviews to reduce NO_X emissions from utility boilers. Application of SCR to existing boilers is being considered for units located in areas designated under Title I (nonattainment provisions) for attainment of the ambient ozone standard. Recent efforts by the Ozone Transport Assessment Group (OTAG) have focused on NO_X reduction strategies on a broader scale, encompassing all states in the central and eastern part of the United States. Results of the OTAG review may increase the likelihood for retrofits of SCR technology, particularly if emission averaging and NO_X trading are allowed. Additionally, nationwide reductions in NO_X mandated under Title IV (acid rain provisions) will be required by the year 2000. In order to meet these additional NO_X reductions, utilities are given flexibility in selecting the most suitable and cost-effective NO_X control technologies for their situation.

This report is written from the perspective of a utility end user of SCR technology. As such, the results are meant to establish a range of financial exposure representative of most domestic electric utilities. It is recognized that there will be utility specific instances where the cost (or cost effectiveness) of SCR technology may be higher or lower than what is contained in this report as evidenced in previous papers representing diverse views regarding the cost of SCR technology. (refer to section 5.0 for a list of reference papers). In an effort to present the most effective economic evaluation possible, information was obtained and incorporated from several sources including:

- Test Facility Data - Measured data and operational lessons learned at the SCS/DOE test facility over the 2-year test program formed the basis of the technical performance estimates.

- Peer Review - Comments were solicited from cofunders, project participants, and independent consultants. The review cycle accomplished a key objective of obtaining peer review of the material as well as challenging the results based on differing viewpoints.

- Technology Suppliers - Analytical and engineering analysis received from vendor participants contributed greatly to the success of the project. The catalyst management plans presented in this report are based on vendor generated laboratory data of catalyst deactivation (k/ko) over time. Additionally, air preheater performance, material testing, and deposit analysis were supplied by the air preheater vendor.

- Full-Scale, Coal-Fired Experience - Results of the economic analysis are enhanced by incorporating current market trends based on SCS participation in one of the first commercial coal-fired SCR installations in the United States. Information from the other U.S. coal-fired SCR installations was also considered when developing the economic evaluation.

The economic evaluation presented in this report is not meant to supplant the need to perform site-specific financial and pro-forma analyses when evaluating SCR technology for a specific project. It is recognized that there will likely be project-specific constraints, sensitivity analyses, and market forces which no generalized economic evaluation will capture. Rather, the information reported herein is presented so the user can modify key financial and technical assumptions to customize the results to a specific situation.

Section 1.0 of this document provides a brief overview of the project and outlines major market drivers for consideration of SCR technology for future NO_X reduction requirements.

Section 2.0 presents a commercial-scale capital and O&M cost evaluation of SCR technology applied to a new facility, coal-fired boiler utilizing high-sulfur, U.S. coal. The base case presented herein determines the total capital requirement, fixed and variable operating costs, and levelized costs for a new 250 MW pulverized coal utility boiler. Economic factors are calculated according to guidelines established by EPRI, taking into account financial parameters such as the cost of capital, income tax rates, and the rate of inflation. Two different sets of factors are calculated to permit the economics to be presented either on a current dollar basis, which includes the effect of inflation, or constant dollar basis which ignores inflation. Reporting of the results are based on "General Guidelines for Public Design Report and Final Report" prepared by Burns and Roe Services Corporation for the DOE Pittsburgh Energy Technology Center (PETC).

Section 3.0 contains sensitivity evaluations which are included to demonstrate the variation in cost due to changes in process variables and assumptions. The following sensitivity cases are included in this evaluation:

- Capital, O&M, and levelized cost for new SCR vs. unit size (60 percent NO_X removal).
- Capital, O&M, and levelized cost for new SCR vs. NO_X removal efficiency (250-MW plant size).
- Levelized cost for new SCR vs. inlet NO_X concentration (250-MW plant size and 60 percent NO_X removal).
- Levelized cost for new SCR vs. catalyst relative activity (catalyst management plans for 250-MW plant size and 60 percent NO_X removal).
- Levelized cost for new SCR vs. return on common equity (ROE for 250-MW plant size and 60 percent NO_X removal).
- Capital, O&M, and levelized cost for new SCR vs. catalyst price (250-MW plant and 60 percent NO_X removal).

Section 4.0 presents the results of a study completed by SCS to determine the cost and technical feasibility of retrofitting SCR technology to selected coal-fired generating units within the Southern electric system. While not the direct result of the SCS/DOE test facility, many of the same methodologies and lessons learned have been applied to utility-scale applications in an effort to maximize the value of the test facility investment to The Southern Company. While retrofit issues will vary from plant to plant and company to company, the results of this study reflect the typically wide range of retrofit costs due to site-specific issues encountered at those plants studied within the Southern electric system.

Section 5.0 contains a list of references which were consulted for supplemental information included in this document.

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2.0 Application of SCR Technology For a New Unit

2.1 Technical Premises

The economic evaluation presented in this section is based on the application of a high-dust, hot-side SCR configuration (i.e., located between the boiler economizer outlet and the air preheater inlet) at a new coal-fired facility. Where applicable, design premises that have a major impact on cost estimating are described in more detail.

The technical design premises used to prepare the economic analysis were selected to be representative of actual or anticipated plant configurations and NO_X control requirements currently being permitted or likely to be permitted on new coal-fired boilers in the United States. Therefore, defining assumptions were selected in an effort to have broad utility applicability. The following paragraphs describe major features of the base case installation.

2.2 250-MW Base Case Unit Description

The base case represents a new, base-load 250-MW pulverized-coal power plant typical of the majority of new coal-fired projects currently under development, construction, or recently declared in commercial operation. The 250 MW plant size is consistent with current and future capacity trends of new domestic power plants. The plant is located in a rural area with minimal space limitations. The fuel is a high-sulfur bituminous Illinois No. 6 coal having an analysis shown in table 1.

Table 1
Coal Analysis Used for Economic Evaluation

Proximate Analysis	Dry Basis	As Received
Ash	9.30 %	8.39 %
Volatile Matter	37.88 %	34.16 %
Fixed Carbon	52.82 %	47.65 %
Moisture		9.80 %
Total	100.00 %	100.00 %

Ultimate Analysis	Dry Basis	As Received
Carbon	74.82 %	67.48 %
Hydrogen	5.00 %	4.51 %
Nitrogen	1.58 %	1.43 %
Sulfur	2.58 %	2.33 %
Chloride	0.16 %	0.14 %
Oxygen	6.56 %	5.92 %
Ash	9.30 %	8.39 %
Water		9.80 %
Total	100.00 %	100.00 %
Higher Heating Value (HHV)	13,265 Btu/lb	12,500 Btu/lb

The plant utilizes a single, balanced-draft, pulverized-coal fired boiler complete with all required auxiliary equipment. The boiler is designed to produce approximately 1,610,000 lb/hr of main steam at turbine inlet conditions of 2400 psig and 1000°F. Utilizing current generation low-NO_X combustion systems, the boiler will produce a NO_X emission rate of 0.35 lb/MBtu. For purposes of this study, it is assumed that tangentially fired boilers and wall-fired boilers are interchangeable with respect to thermal performance and flue gas constituents.

Coal is delivered through gravimetric feeders to the pulverizers and then to the coal nozzles located in the furnace walls. Primary combustion air will flow through the pulverizers to transport the pulverized coal to the furnace. Secondary combustion air from the forced draft fans is preheated in the air preheater and will then be ducted to the boiler windbox to be injected into the furnace through the burners and overfire air ports.

The flue gas exits the boiler and enters a single, hot-side SCR reactor. Flue gas flow is vertically downward through the reactor. The physical arrangement of the SCR is located directly above the air preheater. The SCR is designed as a universal reactor able to accept either (or both) plate- or honeycomb-type catalysts. Nominal generic catalyst module dimensions of 2 meter (l) x 1 meter (w) x 1 meter (h) were assumed for this study. Anhydrous ammonia is used as the reagent. Ammonia injection dilution air will utilize stand alone air fans rather than combustion air from the primary air system.

A single, trisector, Ljungstrom regenerative air preheater is utilized to reclaim heat from the flue gas stream and transfer that heat to the primary and secondary air. The heat transfer surface arrangement includes hot, intermediate, and cold sections. Physical features of the air preheater are typical of what is commercially offered as a deNO_X air preheater as mentioned later in this report. As a result of the air preheater materials testing, the intermediate and cold end heat transfer surface are enamel coated.

Sulfur dioxide removal is accomplished by a lime spray dryer flue gas desulfurization (FGD) system. The FGD system includes two 50-percent absorber vessels equipped with rotary atomizers that produce very fine droplets to enhance the reactivity of the slurry. The absorber vessels will be designed with sufficient residence time to ensure complete evaporation of the water and collection of the acid gases.

A reverse gas, fabric-filter baghouse is used to collect the dried reaction products from the spray dryer as well as the flyash produced in the boiler by the combustion of coal. The baghouse will be constructed in multiple compartments that allow on-line cleaning and maintenance. Each compartment is equipped with a single ash hopper. Clean gas from each compartment passes to an outlet manifold common to all compartments. The clean gas exits out of the baghouse and to the induced draft (ID) fans for discharge out the stack.

Assumptions used to prepare the material balance and combustion calculations for the 250-MW base case unit are shown in table 2. The combustion calculation output for the 250-MW base case is shown in exhibit B.

Table 2
250-MW Base Case Material Balance and Combustion Calculation Assumptions

Unit Capacity (Gross)	250 MW
Capacity Factor	65%
Type of Installation	New facility
Boiler Type	Wall-fired or tangentially fired
Heat Input	2375 MBtu/hr
Coal Feed	190,000 lb/hr
Gross Plant Heat Rate	9500 Btu/kWh
Type of Air Preheaters	Vertical shaft, Ljungstrom
Number of Air Preheaters	One
Air Preheater Outlet Temperature	300°F
Air Preheater Leakage	13%
Excess Air @ Boiler Outlet	18%

2.3 250-MW Base Case SCR Design Criteria

General design criteria for the SCR assumed for this study are shown in table 3. This criteria is predominantly based on the design of the SCR test facility as previously reported in "Plant Crist SCR Project SCR Test Facility Design Basis," Volume 1 and 2 submitted to DOE as the Public Design Report. Where applicable, design criteria have been modified to better reflect operational lessons learned from the test facility and/or current utility industry trends in post combustion NO_X control.

Table 3
250-MW Base Case SCR Design Criteria

Type of SCR	Hot-side
Number of SCR Reactors	One
Reactor Configuration	3 catalyst support layers + 1 dummy layer
Initial Catalyst Load	2 of 3 layers loaded, 1 spare layer
Required Range of Operation	35% to 100% boiler load
NO_X Concentration @ SCR Inlet	0.35 lb/MBtu
Design NO_X Reduction	60%
Flue Gas Temp @ SCR Inlet	700°F
Flue Gas Pressure @ SCR Inlet	-5 in. W.G.
Design Ammonia Slip	5 ppm
Guaranteed Catalyst Life	2 years (16,000 hours)
SO_2 to SO_3 Oxidation	0.75% (initial catalyst load)
Maximum Pressure Drop	6 in. W.G. (fully loaded reactor)
Velocity Distribution	$\Delta V / V_{mean} < 10\%$ over 90% of reactor area
	$\Delta V / V_{mean} < 20\%$ over remaining 10% area
Ammonia Distribution	$\Delta C / C_{mean} < 10\%$
Temperature Distribution	$\Delta T < 10°C$ max deviation from mean

Specific design criteria and technical assumptions which have a major impact on capital and operating cost estimation are described in more detail in the following paragraphs.

2.3.1 SCR Reactor

The following assumptions were used in the development of the SCR reactor capital cost:

- Although the test facility reactors were designed with four catalyst layers plus one flow straightener (dummy layer), this configuration is not thought to be representative of current commercial trends for new units equipped with state of the art low-NO_X burner technology. The test facility reactors were designed with maximum possible flexibility in anticipation of potential problems developing during the test program. The spare layer was not utilized by any catalyst vendor during the test program. It was also assumed that for a new facility with no space limitations, the cross section of the reactor and the height of the catalyst modules could be adjusted within acceptable ranges to allow the initial load of catalyst to be housed in two layers rather than three. Thus, the reactor assumed for this study utilizes a configuration with three catalyst layers plus a flow straightener layer.

- A single, vertical downflow reactor is provided.

- The flow straightener layer consists of fabricated modules of 2 in. x 2 in., 16-gauge mild steel tube approximately 18 inches in length. The design objective for the flow straightener is to ensure that the ratio of hydraulic diameter of the channel openings to the length of flow is sufficient to produce vertical flow streamlines at the inlet to the first layer of catalyst.

- The reactor is equipped with an economizer bypass to permit SCR operation at lower boiler loads. The economizer bypass was sized to allow up to 5 percent of the boiler flue gas flow. It is recognized that the economizer bypass may be different in size or eliminated completely depending on project specific requirements.

- Consistent with many of the new commercial installations, the SCR reactor was assumed to be integral to the boiler house structure and enclosed with a roof and siding.

- All catalyst layers include steam sootblowers. The sootblower design is identical to those used in the test facility.

2.3.2 Initial Space Velocity and Catalyst Volume

Space velocity is a process variable which is used in determining the quantity of catalyst required for a given NO_X removal requirement. Space velocity is defined as the volume of flue gas treated per unit volume of catalyst. The standard convention for expressing flue gas flow rate is in ft^3/hr (m^3/h) corrected to conditions of 32°F (O°C) and 1 atmosphere (1 bar). Catalyst volume is expressed in corresponding units of ft^3 or m^3. Thus, space velocity can be expressed:

$$SV\ (1/hr) = \text{Flue Gas Flow } (ft^3/hr \text{ or } m^3/hr) \,/\, \text{Catalyst Volume } (ft^3 \text{ or } m^3)$$

The relationship between initial space velocity and NO_X removal used in this evaluation is shown in figure 1. The relationship for new units is represented by a least squares curve fit of space velocities taken from the five new coal-fired SCR installations in the U.S. Design information was assembled from commercial bid evaluations, project specific design criteria, and publicly available technical literature. A total of nine data points indicative of both honeycomb- and plate-type catalysts was used to construct the curve. Thus, depending on the project specific evaluation and catalyst geometry selected, the actual space velocity may be slightly higher (as in the case of honeycomb catalyst) or slightly lower (in the case of plate catalyst) than the indicated curve.

The relationship for retrofit units was developed using a least squares curve fit of test facility data measured during parametric testing and each catalyst supplier's proposed space velocity based on the test facility steady state design criteria. The relationship does not represent a single catalyst supplier's offering, but rather a composite of all catalyst space velocities. This approach was selected to provide a reasonable method for estimating space velocity which is independent of catalyst geometry. From a user perspective, this permits consideration of a reactor capable of housing different catalysts ("universal reactor") to allow end-users to evaluate different catalyst offerings directly from the catalyst supplier rather than through a process or system supplier.

2.3.3 Catalyst Life and Catalyst Management Plan

The term "catalyst life guarantee" is often misinterpreted to mean that the performance of the SCR sharply decreases and the entire volume of catalyst must be replaced after the guarantee period. This interpretation is not correct. Performance during early project years (or months) normally exceeds the guaranteed values. Over time, the catalyst performance will gradually deteriorate until the SCR is unable to maintain the required NO_X removal while simultaneously achieving the required ammonia slip. (Most SCR installations operate on a constant NO_X removal to allow continued operation with permitted NO_X emissions at the expense of increased ammonia slip.) Even though the SCR cannot meet guaranteed ammonia slip vs. NO_X performance, the catalyst still has considerable activity remaining.

As noted above, the SCR reactor for this evaluation includes space for three catalyst layers plus a flow straightener. At time zero, two of the three catalyst layers are loaded with catalyst. The third layer, which is empty, allows catalyst suppliers to develop optimized catalyst management plans which increase catalyst utilization. Thus, a fresh catalyst layer can be added to the reactor after the guarantee period when the ammonia slip begins to exceed the guaranteed limit. The activity of the new catalyst combined with the residual activity of the existing catalyst restores the performance of the SCR and extends the next addition/replacement outage beyond the initial guarantee interval.

Catalyst deactivation data were periodically measured by taking catalyst samples from the test facility reactors and returning the samples to the respective catalyst supplier. The catalyst suppliers performed a standard protocol of laboratory and bench scale tests to develop an activity

Space Velocity vs. NOx Removal
SCS/DOE Project - Economic Evaluation

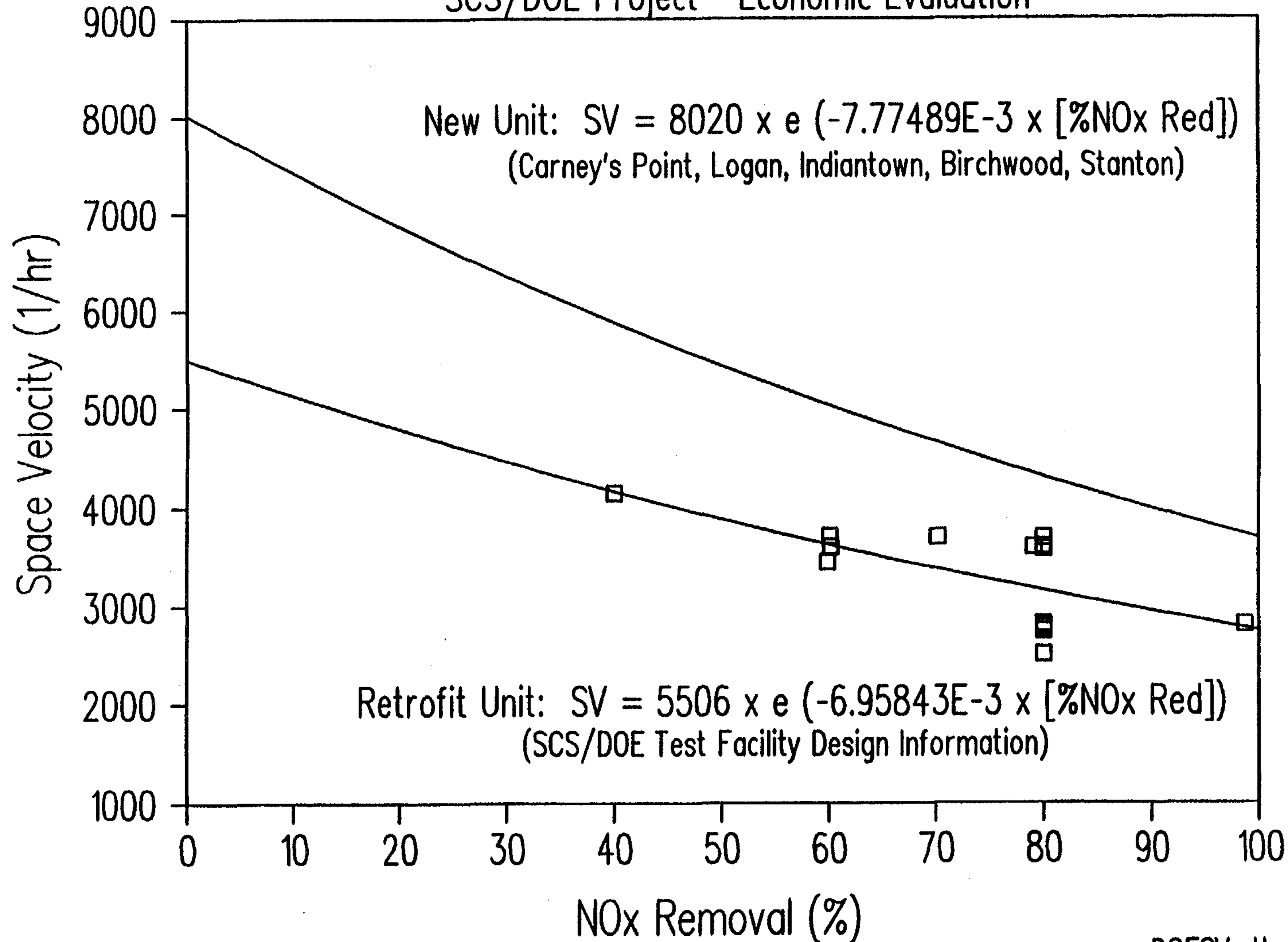


Figure 1

decline vs. operating time relationship. The base case catalyst management plan shown in figure 2 was derived using data collected at the test facility from all catalyst suppliers. Figure 3 shows that a least squares curve fit of catalyst relative activity data from the test facility results in a k/ko value of approximately 0.80 after 16,000 hours. Refer to the catalyst management plan sensitivity section of this report for additional discussion regarding volatility of the k/ko data.

The management plan is based on a 16,000-hour (2-year) catalyst life guarantee period. After the initial guarantee period of 2 years, a new layer of catalyst is added to the reactor spare layer, thus taking advantage of the residual activity in the initial layers to boost the performance of the SCR. The next addition of catalyst is required in project year 6, when one of the initial layers is replaced. After year 6, staged replacement of catalyst layers occurs approximately every three years over the remaining life of the project.

Because the majority of SCR installations contractually obligate the catalyst (or process) supplier to dispose of spent catalyst as part of the initial contract, catalyst disposal costs are not included as part of these cost estimates. This obligation typically is not contingent on catalyst replacement sales. The user pays all shipping costs for transporting the spent catalyst back to the supplier where it is recycled and/or reclaimed. One catalyst supplier has identified a party interested in reclaiming the vanadium as a feedstock for other industrial uses.

2.3.4 Air Preheater

The incremental cost of a deNO_X air preheater (APH) over a non-SCR application air preheater is included in the economic evaluation. Further, based on test facility results provided by ABB Air Preheater, Inc., their recommendation of utilizing enamel coating for the intermediate and cold end heat transfer surface is also included in the evaluation. The following summarizes the air preheater assumptions:

- A single Ljungstrom, regenerative trisector air preheater.

- Intermediate heat transfer surface constructed of 20-gauge (U.S.) low-alloy, corrosion-resistant material. Cold end heat transfer surface constructed of 18 gauge (U.S.) low-alloy, corrosion-resistant material. Normal construction without SCR is 24-gauge (U.S.) open hearth material.

- Intermediate heat transfer surface fabricated with notched flat, 6mm (NF6) surface profile. Normal intermediate surface profile is a more efficient double undulating (DU) surface profile. Cold end heat transfer surface fabricated with NF6 surface profile. Normal cold end surface profile is more efficient with the NF3.5 surface profile.

- With looser, less efficient heat transfer surface in the intermediate and cold end sections, more heat transfer surface will be required to maintain a net zero impact on the thermal performance of the air preheater. More surface area translates to larger, heavier air preheater housing and rotor which requires an upgrade in the support bearing.

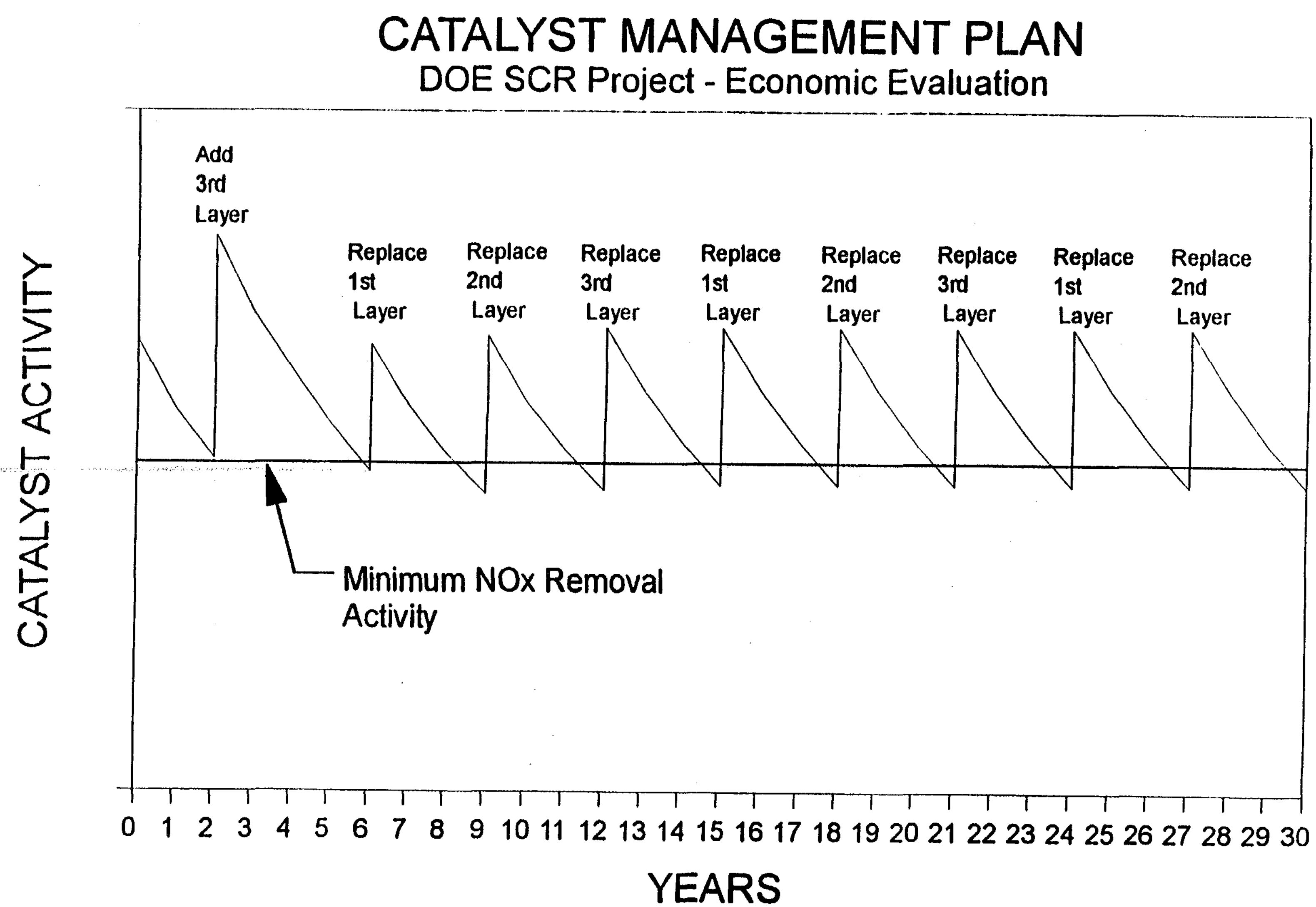
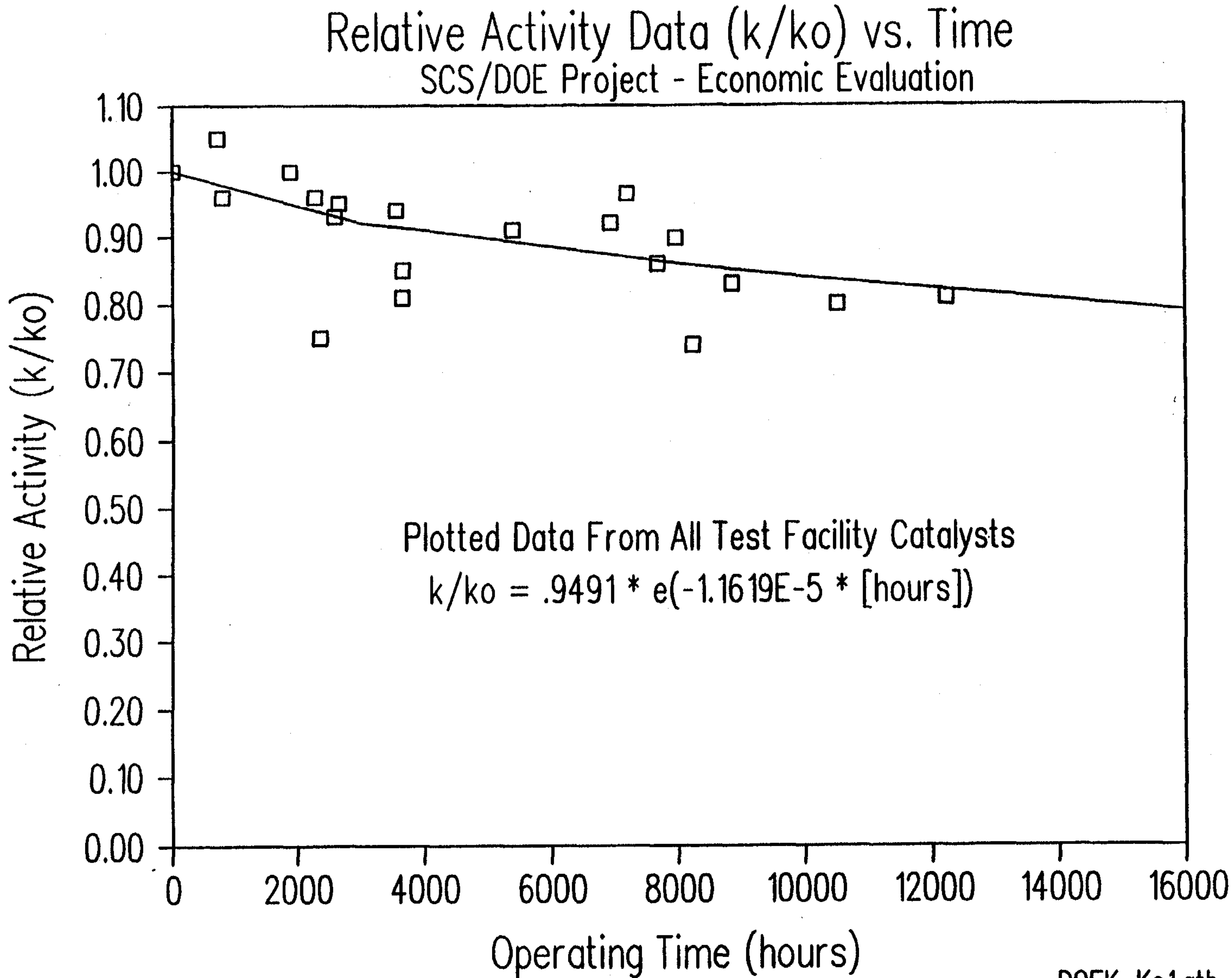

CATALYST MANAGEMENT PLAN
DOE SCR Project - Economic Evaluation
CATALYST ACTIVITY
Add 3rd Layer
Replace 1st Layer
Replace 2nd Layer
Replace 3rd Layer
Replace 1st Layer
Replace 2nd Layer
Replace 3rd Layer
Replace 1st Layer
Replace 2nd Layer
Minimum NOx Removal Activity
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
YEARS

Figure 2



Relative Activity Data (k/ko) vs. Time
SCS/DOE Project - Economic Evaluation
Relative Activity (k/ko)
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0
2000
4000
6000
8000
10000
12000
14000
16000
Plotted Data From All Test Facility Catalysts
k/ko = .9491 * e(-1.1619E-5 * [hours])
Operating Time (hours)
DOEK_Ko1.atb

Figure 3

- As a result of a heat transfer material evaluation performed at the test facility, ABB Air Preheater, Inc., has recommended the use of enamel coating on the intermediate and cold end heat transfer surface. Therefore, this incremental cost is included in the estimate. This also will have an impact on the air preheater weight, requiring further upgrade in support bearings.

- Additional steam sootblowers and water washing equipment are provided on both hot and cold ends of the deNO_X air preheater.

- Slightly higher air leakage rates can be expected with incrementally lower flue gas static pressures.

2.3.5 ID Fan

Comparison of ID fan duty with and without SCR will indicate a differential cost due to increased flow and static pressure requirements for the ID fan with the SCR installation. The economic evaluation includes the incremental capital and O&M cost for the ID fan. The following summarizes the ID fan assumptions:

- Two 55-percent capacity fans with direct drive electric motors and inlet vane control.

- It was assumed that the SCR would increase the test block static pressure +9 inches W.G. This corresponds to a system pressure drop of approximately +6 inches W.G. with a fully loaded reactor. A 2-percent increase in flue gas mass flow rate was assumed due to increased air preheater leakage.

- While no change in ductwork thickness was required, the higher negative pressures required a slight increase in ductwork stiffening steel.

- Incremental cost includes the sum of fan and motor differential costs.

2.3.6 Ammonia Storage, Handling, and Injection System

The following assumptions were used in the development of the ammonia storage, handling, and injection system:

- Anhydrous ammonia delivered by truck.

- One 15,000-gallon tank to provide 10 days of storage at 100 percent boiler load.

- The base case unit utilizes two 100-percent capacity 60-kW electric vaporizers integral to the ammonia storage tank. Higher ammonia consumption due to larger unit size and/or increased NO_X reduction may require the use of steam vaporizers in lieu of electrical vaporizers.

- Ammonia will be conveyed to the ammonia injection grid using dilution air. Three 50-percent capacity dilution air fans will provide dilution air at a ratio of 95 percent air / 5 percent ammonia (by volume).

- The ammonia injection grid will include "tunable" zones to allow optimization of the ammonia injection. The number of zones will vary with the required NO_X removal percentage.

2.4 Economic Premises

The base case economic evaluation includes total capital requirement, fixed and variable operating costs, and levelized costs for a new 250-MW pulverized coal utility boiler. Two different sets of economic factors are calculated to permit the economics to be presented either on a current dollar basis, which includes the effect of inflation, or constant dollar basis which ignores inflation. The methodology used to calculate the economic factors is consistent with guidelines established by EPRI in their Technical Assessment Guide (TAG).

2.5 Economic Evaluation Parameters

A detailed list of economic evaluation parameters used to calculate capital charge and levelization factors is presented in exhibit A. The economic parameters assumed for this evaluation, while not company specific, are representative of typical domestic utility financing. Adjustments in economic assumptions were made, since the construction of an SCR in the context of a new plant will have some shared expenses and economies of scale which are not applicable to stand alone retrofit situations. The assumptions include:

- A 30-year plant life was considered applicable for new SCR construction.

- For purposes of calculating the allowance for funds during construction (AFUDC), the SCR construction period was assumed to be 18 months. This resulted in a multiplier of 1.91 percent for the SCR equipment.

- Construction downtime is not applicable for new construction.

- None of the new coal-fired SCR installations in the United States have included a royalty fee to the end user. Therefore, this cost is assumed to be zero.

- All cost data are presented in 1996 dollars. A 3-percent annual inflation rate is assumed for the current dollar analysis.

A DOE spreadsheet model was utilized to compute the capital charge factors and O&M levelization factors. The model, developed by Burns & Roe Services Corporation for utilization by PETC in evaluating a variety of clean coal technologies, utilizes the EPRI TAG methodology in calculating the applicable financial factors. The factors being utilized for this economic evaluation are presented below in table 4.

Table 4
Capital Charge Factors and O&M Cost Levelization Factors

Current Dollar Analysis:	
Capital Charge Factor	0.150
O&M Cost Levelization Factor	1.362
Constant Dollar Analysis:	
Capital Charge Factor	0.116
O&M Cost Levelization Factor	1.000

2.6 Capital Cost Methodology

The capital cost methodology must reflect all utility costs incurred (including incremental costs) and address a complete scope of supply for a commercial SCR system. For example, the differential cost of an ID fan for a unit without SCR, compared to a unit with SCR, is seldom assessed against the SCR scope of the project. This differential cost, while real to the utility, is more commonly assessed to either a fan or draft system account which does not fully capture the economic impact to balance-of-plant systems due to the SCR. Similarly, differential structural steel cost for the SCR portion of a boiler building is small in the context of the overall boiler building and, therefore, is often included in the boiler building scope and not included as an incremental cost in the SCR scope.

In contrast, the capital cost estimates prepared for this economic evaluation include incremental cost adders applicable to new facilities, which are due to incorporation of SCR into the flue gas train. The following elements are typical of the incremental costs included in the capital cost estimates:

- Incremental boiler house structural steel, siding, and roofing.
- Incremental foundation cost to support the SCR structure.
- Incremental air preheater cost (size, weight, coatings, motor, appurtenances).
- Incremental ID fan (fan and motor) cost due to increased volume and static requirements.
- Incremental ash handling/hoppers due to additional ductwork and/or SCR reactor.

Capital costs were developed based on detailed equipment scope estimates and material take-off quantities. Equipment fabrication and erection estimates were developed using industry standard cost estimating techniques. Much of the cost estimating was accomplished using SCS data based on historical plant design projects. Vendor quotes were obtained for components when little or no data were available or when specific incremental costs were needed. Where possible, validation of the SCR estimates using commercially available literature was used in an effort to reinforce confidence of the estimates. The capital cost also reflects lessons learned from the design, construction, and operation of the SCR test facility.

All capital cost estimates are divided into process areas to provide interested parties sufficient detail to modify costs for project-specific or utility-specific analysis. The major process areas used in the capital cost estimate include:

- Catalyst - Catalyst estimates are applicable for either (or both) honeycomb or plate type catalysts. Current market pricing of $\$400/ft^3$ was the basis of the estimate.

- Reactor Housing, Ductwork, Steel - This area includes all scope associated with the reactor housing; straightening grid (dummy bed); economizer bypass; ductwork; dampers; expansion joints; structural steel; foundations; access platforms; grating; insulation; and flow model study.

- Sootblowers - All catalyst layers include rake-type, retractable steam sootblowers complete with steam piping, valves, insulation, hangers, and steam traps.

- Ammonia Storage, Handling, and Injection - This scope is associated with receiving, storing, handling, and injecting of anhydrous ammonia which includes pressure vessel storage tank(s); steam and/or electric vaporizer; truck unloading facilities; civil works; water deluge/fire protection system; dilution air fans; ammonia piping; valves; multiple-zone, in-duct injection piping; and safety equipment.

- ID Fan Differential - This area reflects the cost differential (fan and motor) due to the increased volume and static pressure duty caused by the SCR. All fans are directly connected with inlet vane control. The SCR will not impact the costs of variable speed drives or fluid couplings.

- Air Preheater Differential - This area captures the incremental cost differences, such as basket material changes, of a $deNO_X$ air preheater relative to a non-SCR application air preheater. Enamel coating of intermediate and cold end heat transfer surface; additional steam sootblowers and water washing equipment; and upgrading of support bearing due to larger, heavier air preheater are other such incremental cost differences which might be present or anticipated.

- Ash Handling Differential - The ammonia slip from a new SCR reactor is assumed to be controlled to prevent unacceptable ammonia-in-flyash contamination and that no flyash treatment systems for ammonia removal will be required. This area captures incremental equipment and pneumatic handling systems present or necessary because of additional ash hoppers either on ductwork or the reactor housing.

- Electrical - The SCR is assumed not to significantly impact the station service transformer or switchyard for a new unit. This area captures the incremental electrical scope (motor control centers, motor starters, cable, conduit, cable tray, etc.) associated with the SCR equipment only.

- Instrument & Controls - This area includes additional instruments such as pressure, flow, and temperature transmitters; wiring; and increased I/O on the plant control system. Inlet and outlet NO_X and O_2 measurement equipment (separate from the plant CEM system) is also included.

- Testing, Training, Commissioning - Costs associated with startup, commissioning, optimization testing, contract acceptance testing, and plant personnel training are included.

Indirect Costs

General facilities are typically calculated as a percentage of total process capital (TPC). A multiplier of 2 percent was assumed for the SCR portion of the general facilities.

Similar to general facilities, engineering and home office fees are also calculated as a percentage of TPC. Because the catalyst is a significant percentage of the capital cost typically engineered by the catalyst supplier, a multiplier of 8 percent of TPC was assumed. This multiplier was an effort to ensure engineering cost is not improperly applied to large, subcontracted items not typically in the scope of the architect/engineer.

The project contingency factor utilized in this evaluation indicates the level of confidence in the total process capital cost of the SCR scope. Project contingencies for a new plant case are lower in comparison to retrofit applications where additional complexity and unknowns related to equipment demolition and relocation can have a significant cost impact.

Project contingency factors are somewhat subjective and reflect an element of uncertainty in both the estimate accuracy and the application of the technology. An overall project contingency of 15 percent was assumed due to offsetting circumstances. High contingency factor circumstances include process uncertainty and operational problems on high-sulfur fuels. Low contingency factor circumstances include unencumbered new unit construction, an estimate that is better than conceptual but not as good as budget, and test facility data.

Preproduction costs as defined by EPRI represent a 1-month total O&M cost (fixed + variable) plus miscellaneous cost items prior to commercial plant operation. For purpose of this evaluation, preproduction costs were estimated using a simpler procedure (as recommended in the DOE guidelines document) in which the total monthly O&M expenses are multiplied by the number of months of anticipated startup operation before the commercial operation date.

$$\text{Preproduction Cost} = \frac{\text{total O\&M costs (less by-product credit) x 2 months of startup}}{\text{12 months}}$$

Inventory capital is calculated as the value of 60 days expendable commodities (assumed to be the variable O&M portion) as defined by the following relationship:

$$\text{Inventory Capital} = \frac{\text{variable O\&M cost (less by-product credit) x 60 days}}{\text{365 days}}$$

Initial catalysts and chemicals are assumed to be zero, since the initial catalyst volume is captured in the direct capital cost and the ammonia, lubricants, and expendables are captured under preproduction and inventory capital costs.

2.7 Operation and Maintenance (O&M) Costs

Fixed O&M costs include estimates of operating labor, maintenance labor, administration/support labor, and maintenance material. Operating labor costs are calculated as the product of the number of operators per shift, the total operating hours per year, and the operating labor pay rate. It was assumed that the SCR would require one plant equipment operator per shift working half-time. The unit labor man-hour rates are included in the fixed and variable O&M assumptions shown in table 5.

Consistent with EPRI's methodology, total maintenance cost is calculated as a percentage of the total process capital and then apportioned between maintenance labor and maintenance material. For processing liquids and gases, a multiplier of 2 percent was used to determine total maintenance. The proportions of 40 percent and 60 percent, respectively, were used to calculate maintenance labor and maintenance material.

Administrative and support labor is calculated as 30 percent of the total operating and maintenance labor costs.

Variable O&M captures the cost of all commodities as well as costs of expendables such as anhydrous ammonia, catalyst addition/replacement, and utilities. Variable O&M also includes the boiler efficiency penalty incurred due to increased APH outlet gas temperature. Because variable O&M costs are dominated by catalyst replacement, the catalyst management plan is one of the most significant factors affecting overall costs of SCR technology. As noted above, a catalyst guarantee life of 2 years along with deactivation data as measured in the test facility were used to determine the catalyst management plan.

There are two possible sources of heat rate (boiler efficiency) penalty due to the application of SCR to a high-sulfur coal unit. The first, which is included in the O&M costs, is due to the increase of SO_3 in the flue gas which results in a higher acid dew point and corresponding higher air preheater outlet gas temperature. Based on the design criteria of 0.75 percent oxidation of SO_2 to form SO_3 across the catalyst, the resulting increase in air preheater outlet gas temperature is approximately 10°F. The penalty was estimated as incremental fuel burned due to loss in boiler efficiency.

The second source of heat rate penalty, which is not included in this estimate, is due to the required operation of the SCR at lower boiler loads when bypass of the economizer is necessary to maintain the minimum operating temperature of the SCR. Because it is assumed that the new unit dispatches as a base load unit, it is anticipated that this penalty will be small. However, as evidenced in the retrofit section where the cycling pattern of a given unit is known, the economic penalty for low-load operation can be significant.

Table 5
Fixed and Variable O&M Assumptions and Unit Costs

SCR inlet NO_X	0.35 lb/MBtu
SCR reduction efficiency	60%
Anhydrous ammonia cost	$250/ton
SCR catalyst cost	$400/ft^3
SCR catalyst guarantee period	2 years
SCR catalyst escalation	3.0%
Power cost	30 mills/kWh
ID fan efficiency	75%
SCR draft loss (fully loaded reactor)	3.0 in. W.G.
Ductwork draft loss	0.75 in. W.G.
Ammonia injection grid draft loss	0.75 in. W.G.
Unrecoverable air preheater draft loss	1.0 in. W.G.
Fuel cost (delivered)	$2.00/MBtu
Operating labor man-hour rate	$23.00/hr
Maintenance factor (% of total process capital)	2.0%

The following O&M costs were not included in this evaluation due to the difficulty in estimating the overall impact:

- Catalyst Disposal - Based on current commercial experience, it is assumed that the catalyst supplier would take back spent catalysts.

- Sootblowing Steam - Superheated sootblowing steam required for the SCR was assumed to be small in comparison to the amount used by the boiler.

Table 5 presents the assumptions and unit costs used to calculate the fixed and variable O&M costs for the base case evaluation.

2.8 250-MW Base Case Results

Exhibit D contains detailed results of the capital, O&M, and levelized costs for the 250-MW base case unit. The total capital requirement for a new SCR installation was estimated at $54/kW or $13,415,000 in 1996 dollars. Total first year O&M is $1,045,000 in 1996 dollars. Table 6 summarizes the results shown in exhibit D.

Table 6
250-MW Base Case - New SCR Results

Total Capital Requirement	\$ 13,415,000
Total Capital Requirement	\$ 54/kW
First Year Fixed Operating Cost	\$ 312,000/yr
First Year Variable Operating Cost	\$ 733,000/yr
Current Dollar Analysis	
Levelized Cost (mills/kWh)	2.57
Levelized Cost (\$/ton NO_X Removed)	\$2,500
Constant Dollar Analysis	
Levelized Cost (mills/kWh)	1.85
Levelized Cost (\$/ton NO_X Removed)	\$1,802

The base case results include some interesting comparisons related to the influence of catalyst cost on the capital and O&M cost of an SCR. The catalyst accounts for approximately 21 percent of the total process capital for the SCR installation. From an O&M perspective, catalyst is approximately 61 percent of the variable O&M and 43 percent of the total annual O&M cost. This result underscores the fact that O&M costs are dominated by catalysts.

When comparing SCR with other NO_X reduction alternatives, the higher capital costs of SCR dominate the levelized cost. For the 250-MW base case, the capital cost is 59 percent of the current dollar total levelized cost, indicating a major portion of the levelized cost is going toward debt service (revenue requirement) of the capital investment rather than operating costs.

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3.0 Sensitivity Analyses (Effect of Variables on Economics)

Sensitivity analyses were performed to examine the impact of major process variables on the capital, O&M, and levelized cost of SCR technology. The major sensitivity cases examined as part of this evaluation are summarized in the following sections.

3.1 Capital, O&M, and Levelized Cost for New SCR Vs. Unit Size (60 Percent NO_X Removal)

In order to examine the change in SCR costs vs. unit size, additional capital and O&M estimates were prepared for a 125-MW unit and 700-MW unit. To maintain consistency with the 250-MW base case unit, an SCR removal efficiency of 60 percent NO_X reduction was assumed. Where possible, consistent (or identical) assumptions were made with regard to the 125-MW and 700-MW units.

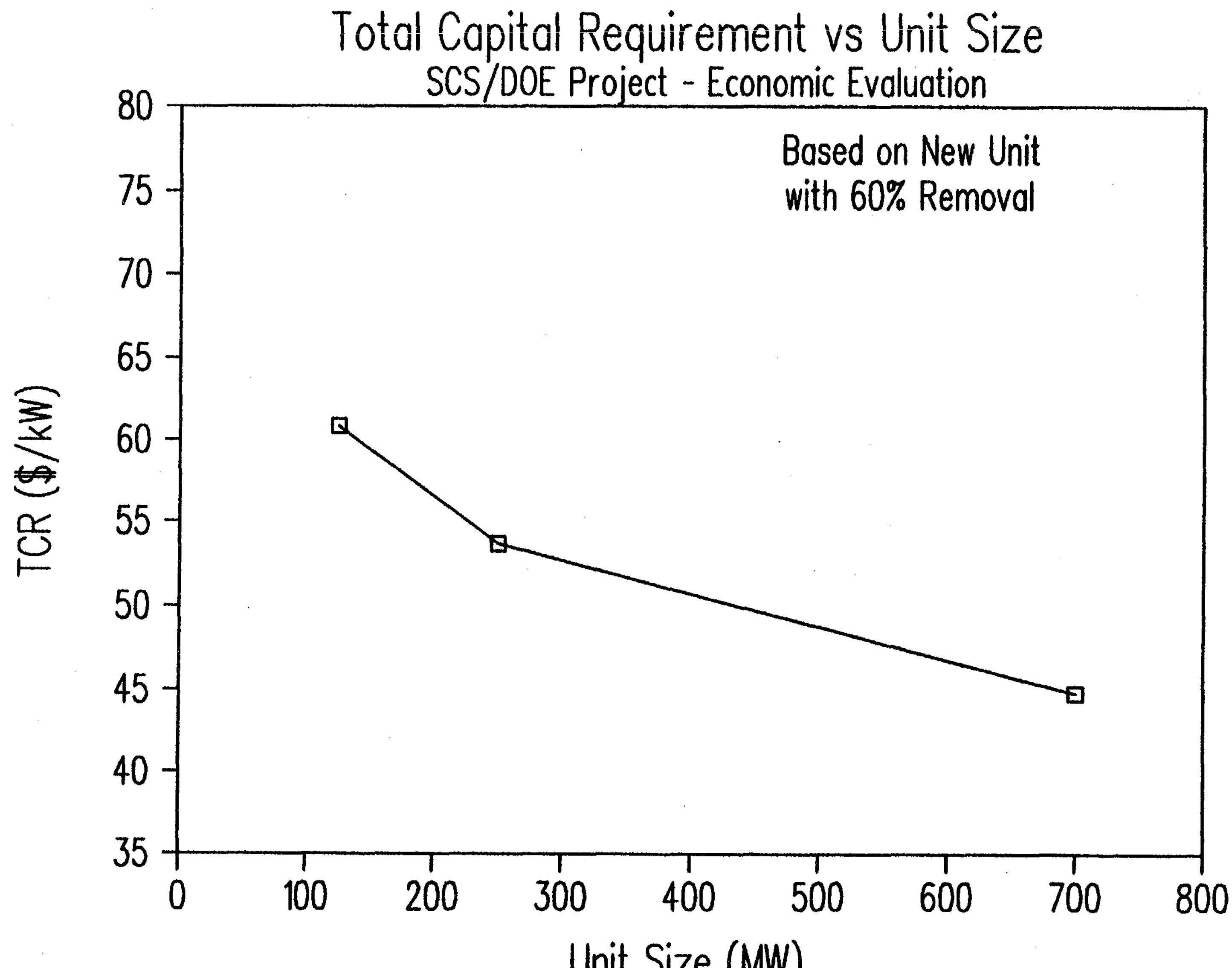
The combustion calculations for a new 125-MW unit are shown in exhibit F. All assumptions used to prepare the combustion calculation are identical to the 250-MW base case unit. The resulting heat input and coal feed are 1,188 MBtu/hr and 95,000 lb/hr, respectively. A single SCR reactor having similar design criteria as the 250-MW base case (shown in table 3) is assumed for the 125-MW size unit.

The combustion calculations for a new 700-MW unit are shown in exhibit H. All assumptions used to prepare the combustion calculation are identical to the 250-MW base case unit. The resulting heat input and coal feed are 6,650 MBtu/hr and 532,000 lb/hr, respectively. Due to the size of the 700-MW unit, it is assumed that the draft train is split into two 50-percent capacity SCR reactors, each one having similar design criteria as the 250-MW base case (shown in table 3). Two air preheaters are assumed for the 700-MW unit.

When plotted in $/kW vs. unit size, the total capital requirement of the SCR system shows a trend of decreasing unit cost with increasing unit size, indicating significant economy of scale. Total capital requirement ranges from $61/kW for the 125-MW unit to $45/kW for the 700-MW unit. Figure 4 shows a graphical representation of total capital requirement ($/kW) vs. unit size.

Figure 5 shows the levelized cost ($/ton) vs. unit size. The levelized cost decreases with increasing unit size due, in part, to larger NO_X tonnages removed; however, the trend does not appear to be overly sensitive to unit size.

Tabular results showing capital, O&M, and levelized cost vs. unit size for an SCR with 60 percent NO_X removal efficiency are summarized in table 7.



Total Capital Requirement vs Unit Size
SCS/DOE Project - Economic Evaluation
Based on New Unit
with 60% Removal
TCR ($/kW)
80
75
70
65
60
55
50
45
40
35
0
100
200
300
400
500
600
700
800
Unit Size (MW)
DOESIZE2.atb

Figure 4

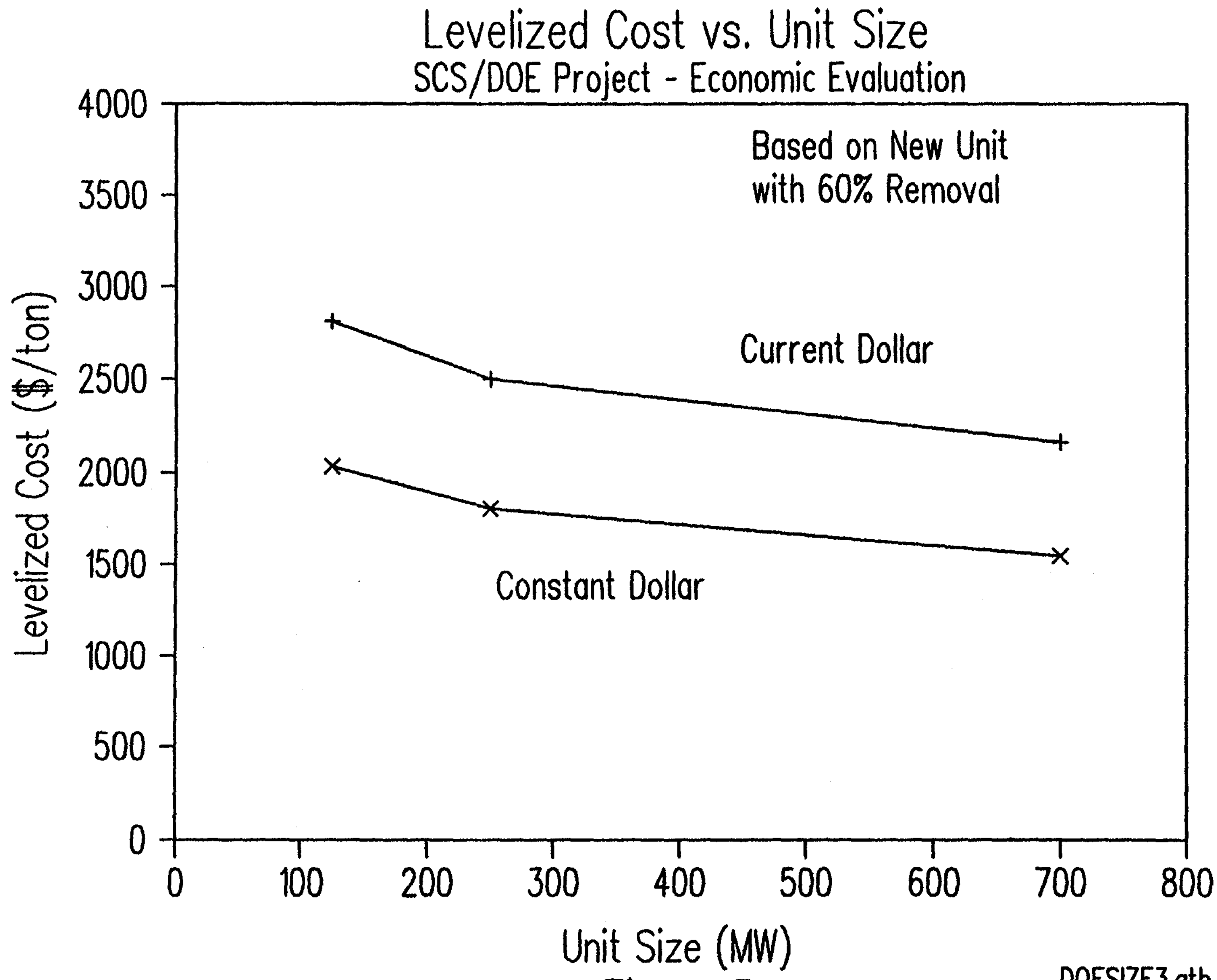

Levelized Cost vs. Unit Size
SCS/DOE Project - Economic Evaluation
Based on New Unit
with 60% Removal
Current Dollar
Constant Dollar
Levelized Cost ($/ton)
4000
3500
3000
2500
2000
1500
1000
500
0
0
100
200
300
400
500
600
700
800
Unit Size (MW)
DOESIZE3.atb

Figure 5

Table 7
Capital, O&M, and Levelized Cost for New SCR Vs. Unit Size
(60 Percent NO_X Removal)

	Unit Size (MW)		
		Base Case	
	125-MW	250-MW	700-MW
Total Capital Requirement	$7,602,000	$13,415,000	$31,327,000
Total Capital Requirement	$ 61/kW	$54/kW	$45/kW
First Year Fixed Operating Cost	$ 213,000	$312,000	$614,000
First Year Variable Operating Cost	$ 367,000	$ 733,000	$2,053,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	2.89	2.57	2.22
Levelized Cost ($/ton)	$2,811	$2,500	$2,165
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	2.09	1.85	1.59
Levelized Cost ($/ton)	$2,037	$1,802	$1,547

Exhibits G and I include capital, O&M, and levelized cost summaries for the 125-MW and 700-MW units, respectively. The 250-MW base case unit summary is included in exhibit D.

3.2 Capital, O&M, and Levelized Cost for New SCR Vs. NO_X Removal Efficiency (250-MW Plant Size)

In addition to the 250-MW base case with a NO_X removal efficiency of 60 percent, two additional NO_X removal cases at 40 percent and 80 percent were calculated to examine the impact of levelized cost vs. NO_X removal efficiency.

Figure 6 shows the levelized cost ($/ton) vs. NO_X removal efficiency. The levelized cost decreases with increasing NO_X removal percentages and is fairly sensitive to the percentage removal. Thus, once committed to an SCR, significant levelized cost savings ($/ton) can be realized for an incremental increase in capital cost. As seen in table 8, the incremental capital cost difference between 40 percent and 80 percent removal is $1,168,000 or approximately a 9 percent increase in capital cost over the 40 percent design. The corresponding difference in current dollar levelized cost is $1466/ton, a 58 percent decrease in $/ton cost from the 80 percent case compared to the 40 percent case. This difference is primarily due to the increased number of tons removed at 80 percent vs. 40 percent.

This trend in lower levelized cost is also very evident in high-NO_X emitting boilers where similar NO_X removal designs (as a percentage) yield lower $/ton due to a larger number of tons removed.

Levelized Cost vs. NOx Removal

SCS/DOE Project - Economic Evaluation

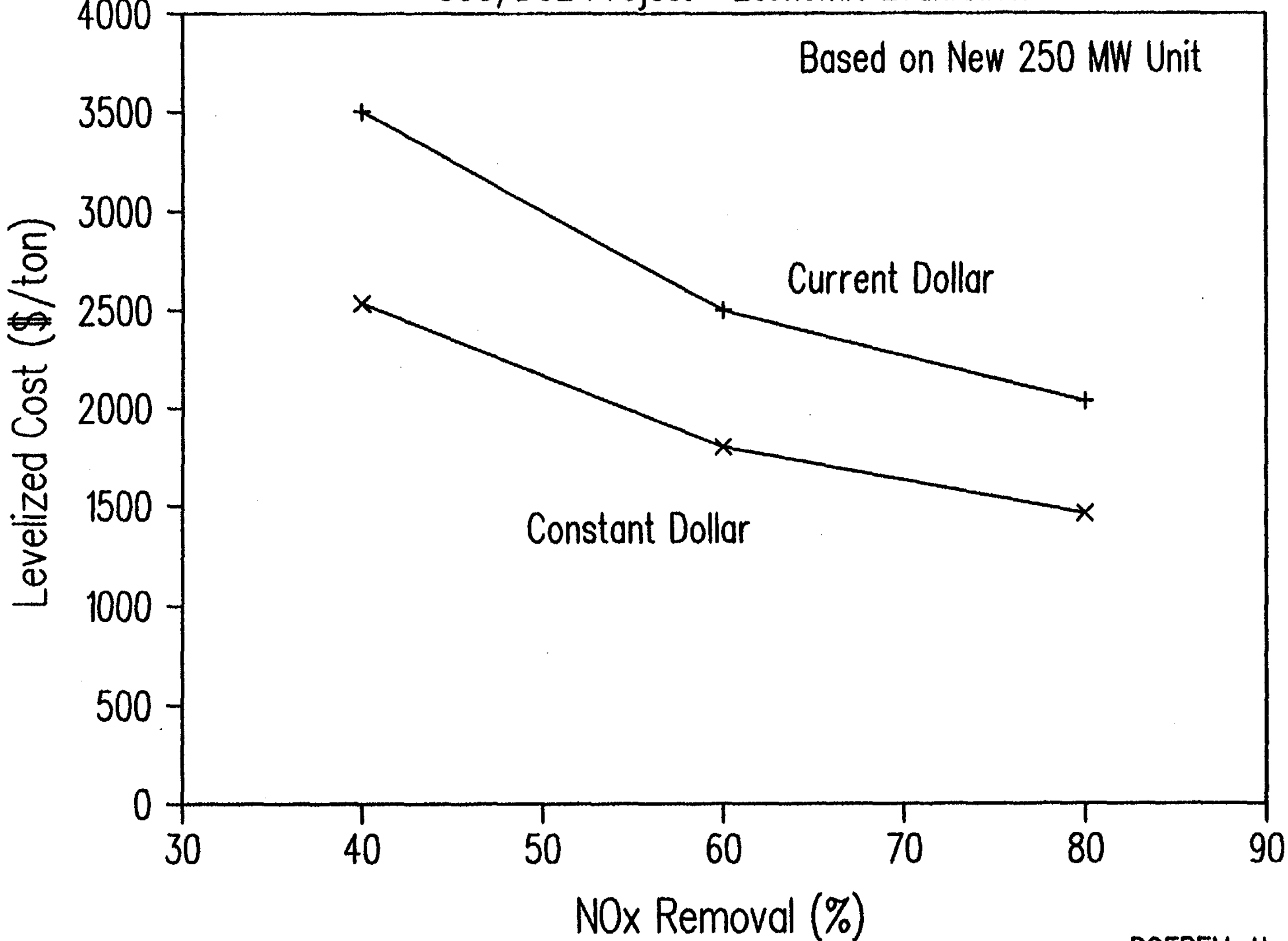


Figure 6

DOEREM.atb

Tabular results showing capital, O&M, and levelized cost vs. NO_X removal efficiency for a 250-MW unit are summarized in table 8.

Table 8
Capital, O&M, and Levelized Cost for New SCR Vs. NO_X Removal Efficiency (250-MW Plant Size)

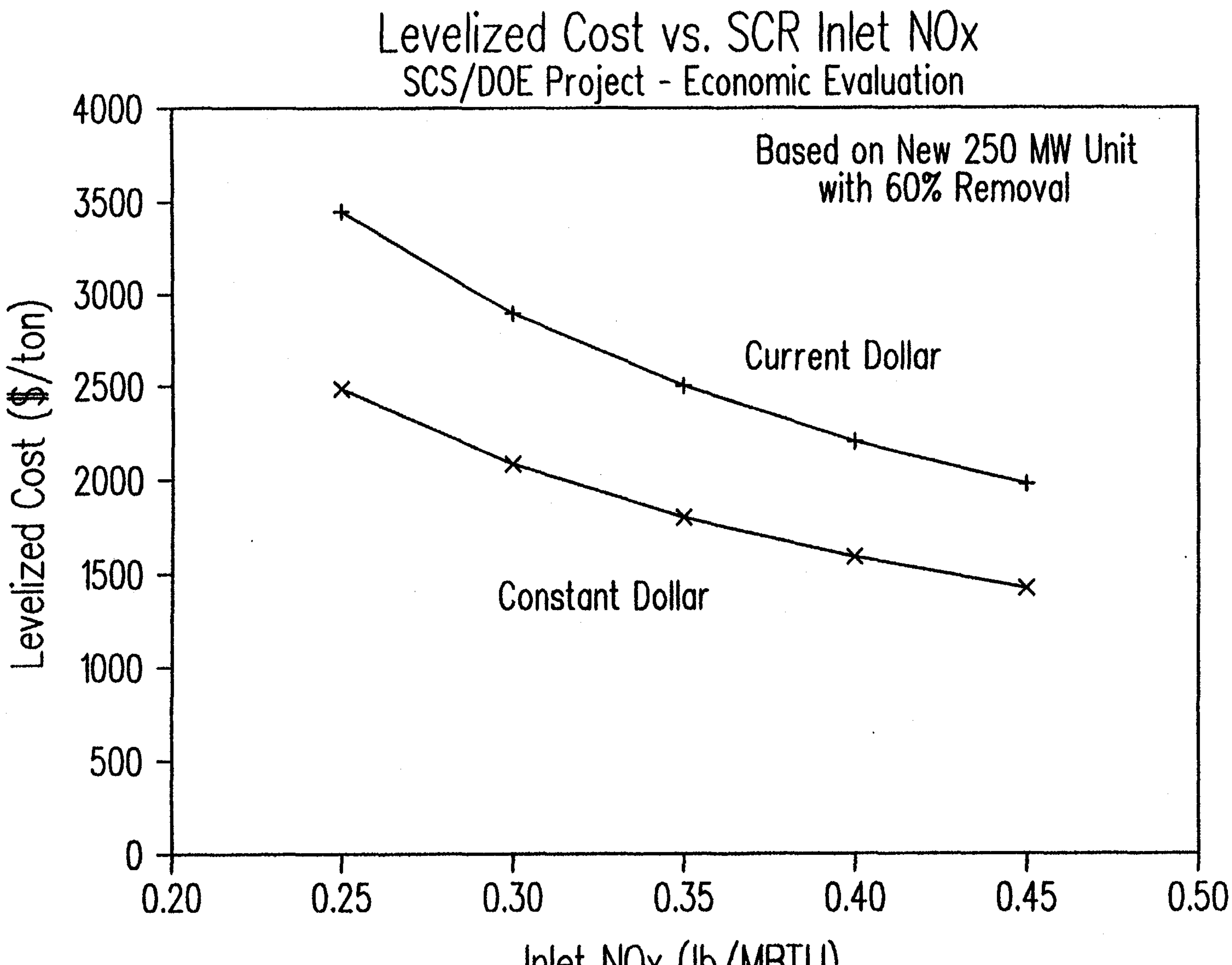
	NO_X Removal Efficiency		
		Base Case	
	40%	60%	80%
Total Capital Requirement	$12,974,000	$13,415,000	$14,142,000
Total Capital Requirement	$52/kW	$54/kW	$57/kW
First Year Fixed Operating Cost	$305,000	$312,000	$324,000
First Year Variable Operating Cost	$621,000	$733,000	$857,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	2.39	2.57	2.79
Levelized Cost ($/ton)	$3,502	$2,500	2,036
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	1.74	1.85	2.00
Levelized Cost ($/ton)	$2,536	$1,802	$1,460

Exhibits C, D, and E include 250-MW unit capital, O&M, and levelized cost summaries for the 40 percent, 60 percent, and 80 percent NO_X removal cases, respectively.

3.3 Levelized Cost for New SCR Vs. Inlet NO_X Concentration (250-MW Plant and 60 Percent NO_X Removal)

Many new boiler installations face difficult decisions on how to best optimize overall NO_X reduction requirements using a combination of a low-NO_X combustion system and SCR. While maximizing combustion NO_X reductions can allow lower SCR variable O&M, it may have a negative impact to plant cycle efficiency due to increased LOI in the flyash. Increased carbon monoxide production may also be a limiting factor during deep staged combustion. Optimizing the combustion system to minimize LOI can lead to higher NO_X concentrations entering the SCR and, therefore, higher variable O&M costs to achieve a permitted outlet NO_X emission limit.

The relationship between levelized cost ($/ton) vs. SCR inlet NO_X concentration shown in figure 7 indicates a significant trend of increasing levelized cost with decreasing inlet NO_X concentration. In this case, fewer tons of NO_X are removed by the SCR, highlighting a key difference in cost effectiveness between a controlled new unit application and an uncontrolled (or higher NO_X emitting) retrofit application. A constant 60-percent NO_X removal percentage was applied to all inlet NO_X concentrations shown in figure 7.



Levelized Cost vs. SCR Inlet NOx
SCS/DOE Project - Economic Evaluation
Based on New 250 MW Unit
with 60% Removal
Current Dollar
Constant Dollar
Levelized Cost ($/ton)
4000
3500
3000
2500
2000
1500
1000
500
0
0.20
0.25
0.30
0.35
0.40
0.45
0.50
Inlet NOx (lb/MBTU)
DOENOIN.atb

Figure 7

Tabular results showing levelized cost vs. SCR inlet NO_X concentration for a 250-MW unit operating at 60 percent NO_X removal are summarized in table 9.

Table 9
Levelized Cost for New SCR Vs. SCR Inlet NO_X Concentration
(250-MW Plant and 60 Percent NO_X Removal)

	Inlet NO_X Concentration (lb/MBtu)				
			Base Case		
	<u>0.45</u>	<u>0.40</u>	<u>0.35</u>	<u>0.30</u>	<u>0.25</u>
Current Dollar Analysis					
Levelized Cost (mills/kWh)	2.61	2.59	2.57	2.55	2.53
Levelized Cost ($/ton)	$1,977	$2,205	$2,500	$2,894	$3,446
Constant Dollar Analysis					
Levelized Cost (mills/kWh)	1.88	1.87	1.85	1.84	1.82
Levelized Cost ($/ton)	$1,425	$1,590	$1,802	$2,086	$2,483

Detailed summary sheets for levelized cost as a function of inlet NO_X are included in exhibit J.

3.4 Levelized Cost for New SCR Vs. Catalyst Relative Activity (Catalyst Management Plan) (250-MW Plant and 60 Percent NO_X Removal)

One of the key results produced at the test facility is the catalyst deactivation data collected over the duration of the test program. The variation among selected catalyst deactivation data has been correlated in an attempt to create a range of catalyst management strategies for evaluation.

Relative activity (k/ko) is defined as the activity of the catalyst at a given operating time, k, divided by the activity of the new catalyst at time zero, ko. As noted previously, catalyst deactivation measurements were periodically taken by removing catalyst samples from the reactors and returning the samples to the respective catalyst supplier for analysis. Each catalyst supplier performed a standard protocol of laboratory and bench scale tests to determine the k/ko relationship vs. time for their respective catalyst. Because the relative activity data indicate a wide variation in values as well as the fact that each catalyst supplier extracted an unequal number of catalyst samples at different times intervals over the test period, three sets of individual catalyst data were identified for further evaluation.

All of the catalyst management plans included in this evaluation are based on a 16,000 hour (2-year) catalyst life guarantee period. Because there is very little data beyond 8000 operating hours, development of a relationship showing decline of relative activity over time must be extrapolated to some extent. The catalyst management plans developed for sensitivity evaluation are based on k/ko data having values of 0.90, 0.80, and 0.70 after 16,000 hours.

Figures 8, 9, and 10 set forth the declining k/ko relationship over time that results in a value after 16,000 hours of 0.90, 0.80, and 0.70, respectively. Taken alone, each figure appears to have a reasonable relationship based on an exponential decline over time. Given the scarce amount of data beyond 8,000 hours, and the differences in specific catalyst selected, any of the k/ko scenarios in figures 8 through 10 are reasonably plausible and are equally likely to occur. Figure 11 shows k/ko data plotted for all catalysts used in the test program, with the three exponentially declining curves overlaid on the data. The range of curves set the limit for the upper (k/ko = .90) and lower (k/ko = .70) bounds of the relative activity variation.

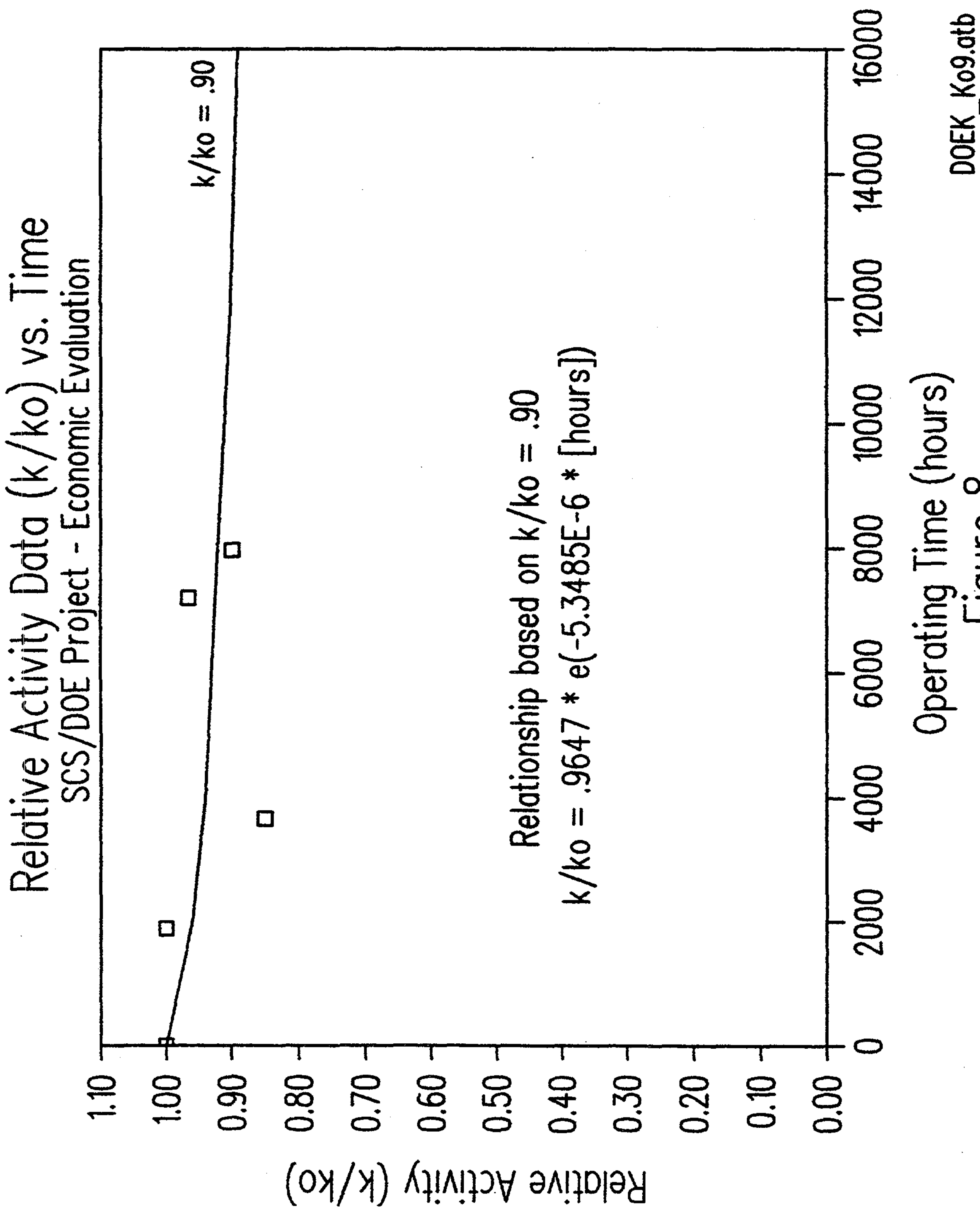
The base case catalyst management plan was selected with a k/ko value of 0.80 for several reasons:

- Figure 9 shows the relative activity relationship for a particular catalyst having the greatest number of data points past 8000 hours. The data appears to reasonably correlate with a k/ko value of 0.80 after 16,000 hours with very little extrapolation.
- Figure 11 shows that a k/ko value of 0.80 after 16,000 is a reasonable median value over the range of possible values.
- Publicly reported commercial experience at two of the new coal-fired SCR installations in the U.S. appears to support the conclusion reached at the test facility that a relative activity of 0.80 after 2 years of operation is reasonable and is representative of U.S. commercial applications as of this writing.

Using the relative activity data, catalyst management plans were developed which define the catalyst replacement schedule over the project life. Knowing the volume of catalyst as well as the time which it is added, project cash flows can be developed. Table 10 indicates the project year in which one layer of catalyst is added and/or replaced.

Table 10
Catalyst Management Plan
Project Years to Add and/or Replace One Layer of Catalyst

k/ko = .70	k/ko = .80	k/ko = .90
2	2	2
5	6	12
7	9	17
9	12	23
12	15	
14	18	
16	21	
19	24	
21	27	
23		
26		
28		



Relative Activity Data (k/ko) vs. Time
SCS/DOE Project - Economic Evaluation
Relationship based on k/ko = .90
k/ko = .9647 * e(-5.3485E-6 * [hours])
k/ko = .90
Relative Activity (k/ko)
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0
2000
4000
6000
8000
10000
12000
14000
16000
Operating Time (hours)
DOEK_Ko9.atb

Figure 8

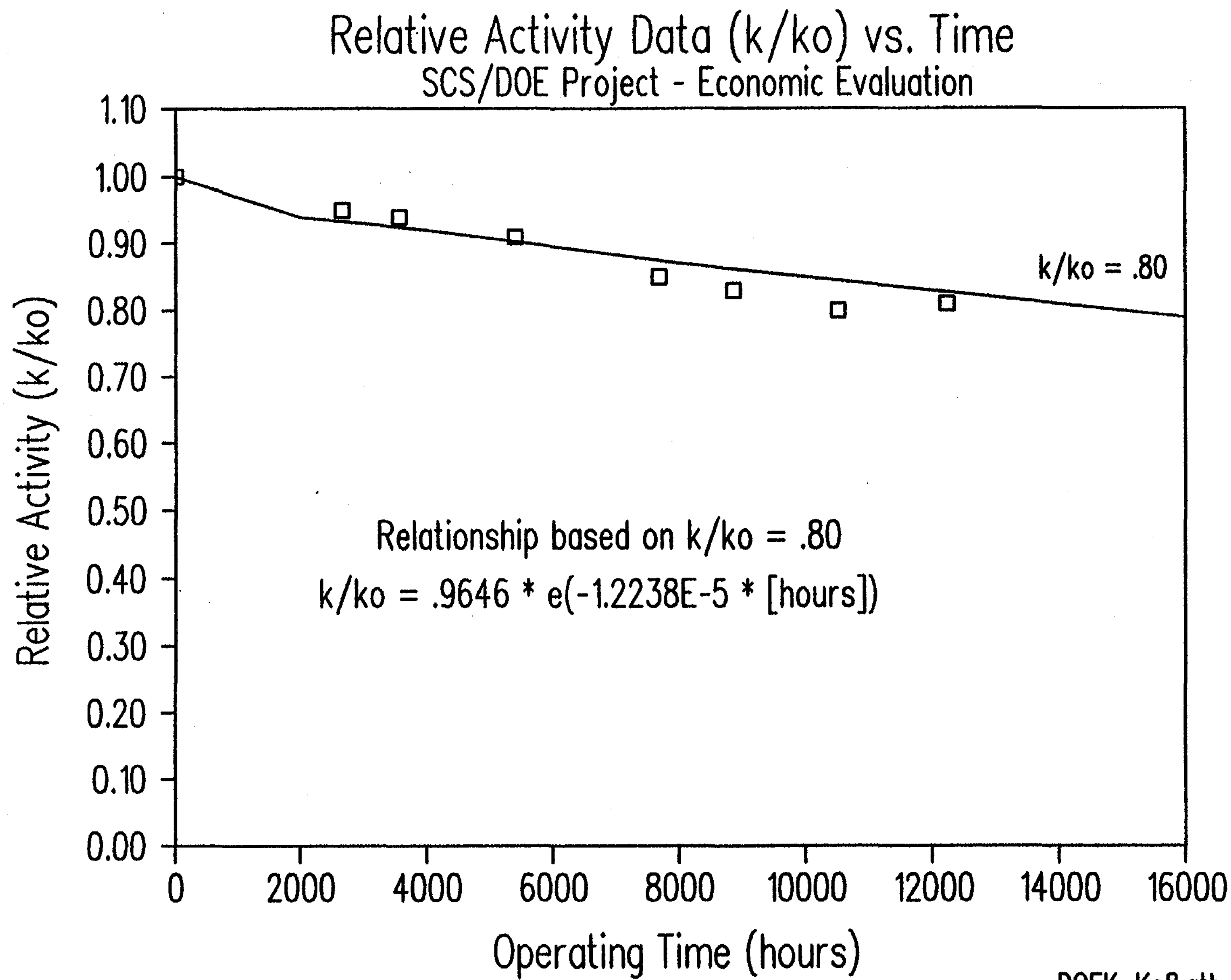

Relative Activity Data (k/ko) vs. Time
SCS/DOE Project - Economic Evaluation
Relative Activity (k/ko)
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0
2000
4000
6000
8000
10000
12000
14000
16000
k/ko = .80
Relationship based on k/ko = .80
k/ko = .9646 * e(-1.2238E-5 * [hours])
Operating Time (hours)
DOEK_Ko8.atb

Figure 9

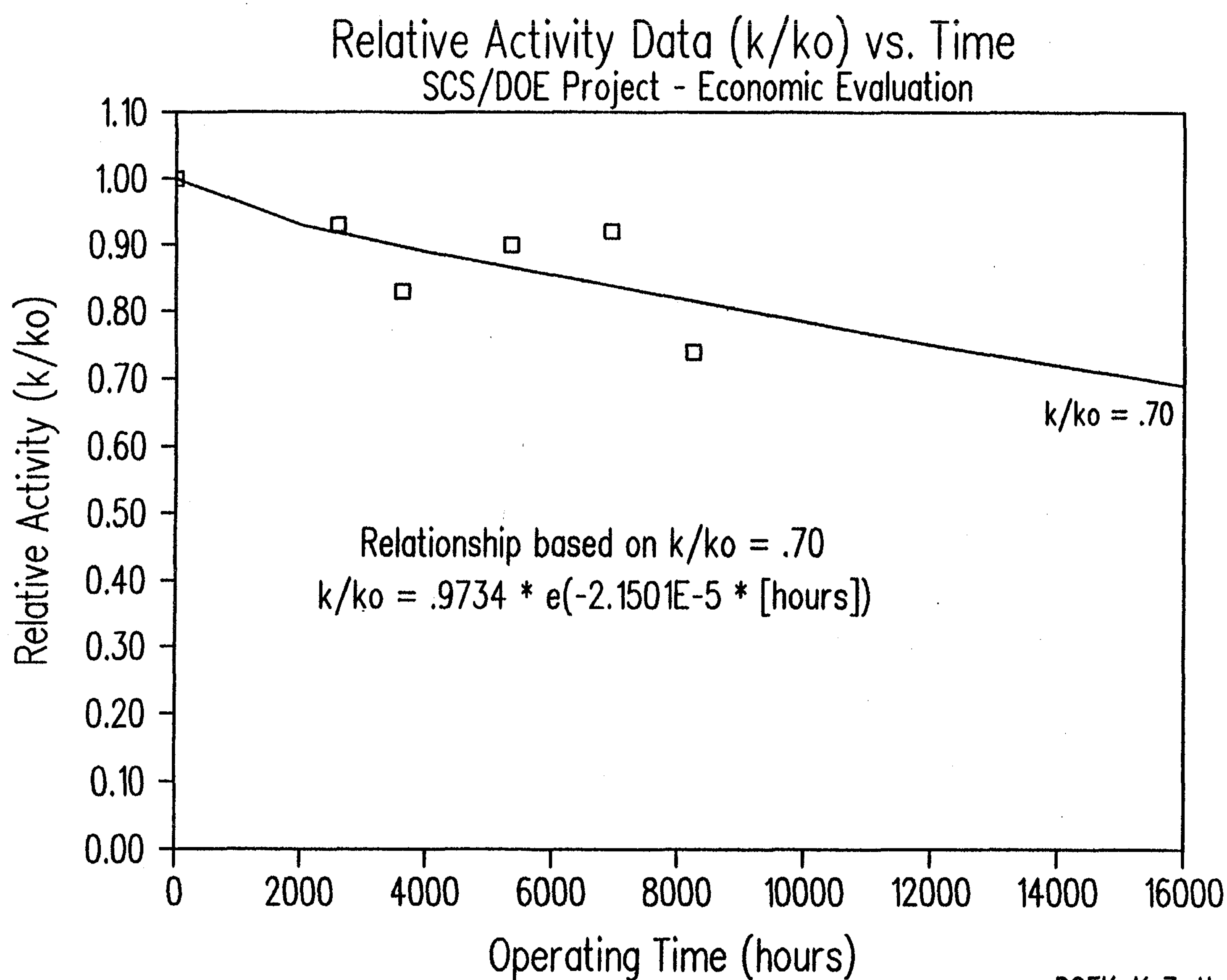

Relative Activity Data (k/ko) vs. Time
SCS/DOE Project - Economic Evaluation
Relative Activity (k/ko)
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0
2000
4000
6000
8000
10000
12000
14000
16000
k/ko = .70
Relationship based on k/ko = .70
k/ko = .9734 * e(-2.1501E-5 * [hours])
Operating Time (hours)
DOEK_Ko7.atb

Figure 10

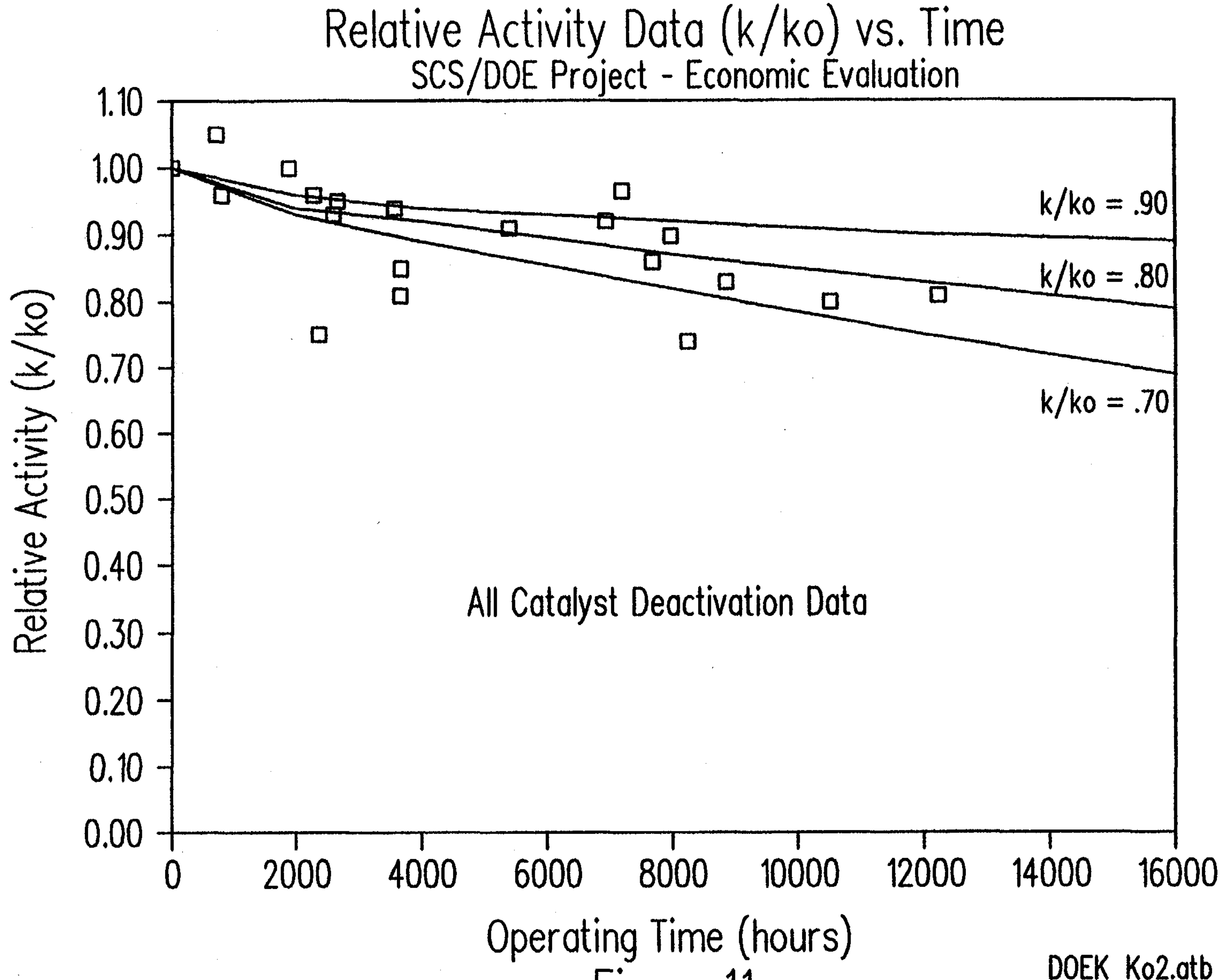

Relative Activity Data (k/ko) vs. Time
SCS/DOE Project - Economic Evaluation
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Relative Activity (k/ko)
k/ko = .90
k/ko = .80
k/ko = .70
All Catalyst Deactivation Data
0
2000
4000
6000
8000
10000
12000
14000
16000
Operating Time (hours)
DOEK_Ko2.atb

Figure 11

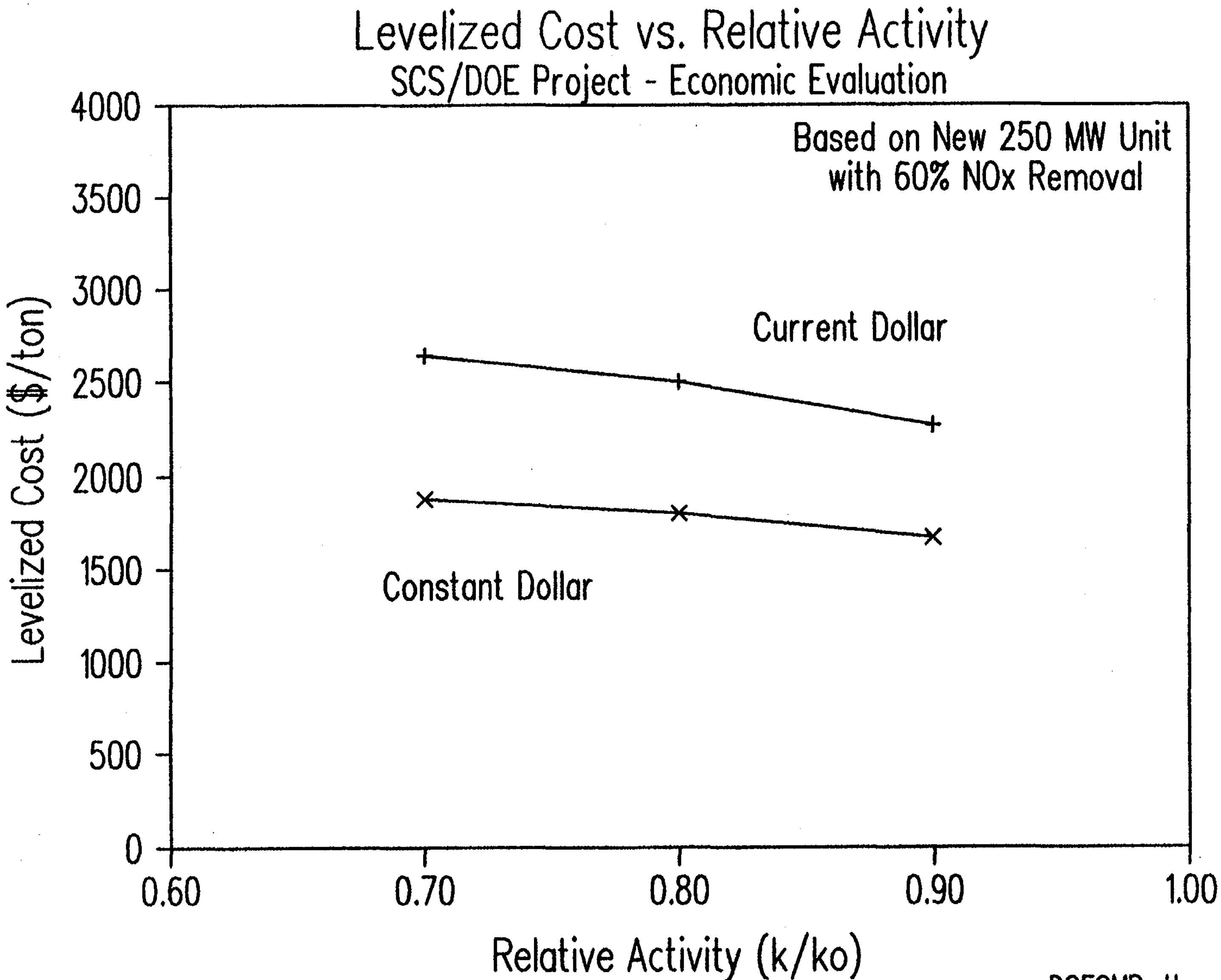
Table 11 shows the range of total catalyst volume and levelized cost for the three different catalyst management plans. While the total catalyst volume between the most optimistic (k/ko = 0.90) and most pessimistic (k/ko = 0.70) management plans varies by 21,664 ft^3 (a factor of three times), the current dollar levelized cost varies only $373/ton or a difference of only 14 percent (see figure 12). All three catalyst management plans are based on a common 2-year catalyst life guarantee period. So, even though the k/ko = .70 plan adds three times as much catalyst, the catalyst is added in later project years, which has less effect when performing a present value analysis and levelizing to calculate the equivalent annual catalyst cost. This is clearly evident in the fact that the catalyst cost difference between the two cases is $377,000 per year, representing a 64-percent difference in annual O&M dollars (see figure 13). Additionally, if the costs of catalyst disposal were factored in, the expected result would be more pronounced because the k/ko = 0.70 plan would need to dispose of three times as much catalyst.

Detailed summary sheets for levelized cost as a function of different catalyst management plans are included in exhibit K.

Table 11
Levelized Cost for New SCR Vs. Catalyst Relative Activity
Catalyst Management Plan Results for 250-MW Plant and 60 Percent NO_X Removal

	k/ko = .90	k/ko = .80	k/ko = .70
Total Catalyst Volume Added or Replaced Over the Life of the Plant (ft^3)	10,832	24,372	32,496
Equivalent Annual Current Dollar Catalyst Cost	$216,000	$450,000	$593,000
Equivalent Annual Constant Dollar Catalyst Cost	$144,000	$325,000	$433,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	2.33	2.57	2.71
Levelized Cost ($/ton)	$2,269	$2,500	$2,642
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	1.72	1.85	1.93
Levelized Cost ($/ton)	$1,671	$1,802	$1,881

It is anticipated that the levelized cost will be very sensitive to timing of catalyst replacement in early years of the project. This is a key issue to consider when contemplating a new project and performing sensitivity analyses to the project pro-forma. Additional efforts might include changing the timing of the catalyst addition as a function of relative activity. For example, the base case management plan based on k/ko = .80 after 2 years would have a positive and negative variant representing a better than expected result (i.e., k/ko = .90 indicates first catalyst addition is actually required after 3 years rather than 2 years) and a worse than expected result (i.e., k/ko = .70 indicates the first catalyst addition is actually required after 1 year rather than 2 years).


Levelized Cost vs. Relative Activity
SCS/DOE Project - Economic Evaluation
Based on New 250 MW Unit
with 60% NOx Removal
Current Dollar
Constant Dollar
Levelized Cost ($/ton)
4000
3500
3000
2500
2000
1500
1000
500
0
0.60
0.70
0.80
0.90
1.00
Relative Activity (k/ko)
DOECMP.atb
Figure 12

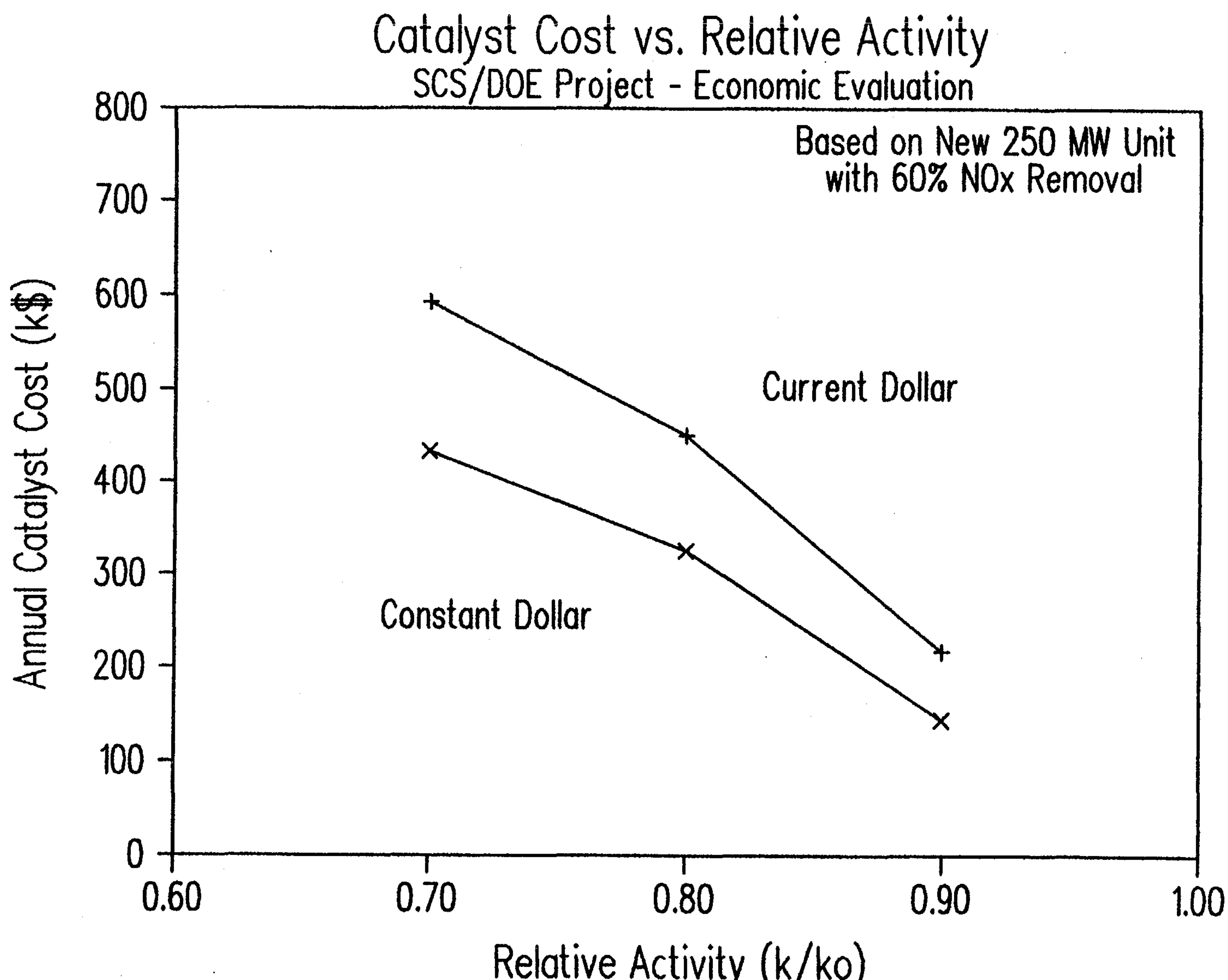


Figure 13

DOECMP2.atb

3.5 Levelized Cost for New SCR Vs. Return on Common Equity (ROE) (250-MW Plant and 60 Percent NO_X Removal)

The domestic electric utility industry is in transition from a predominantly regulated environment to a more market driven, less regulated environment. There is much uncertainty in the future earning potential of major capital investments such as SCR technology. This regulatory uncertainty is best illustrated by a recent decision in New Hampshire where the Public Utilities Commission disallowed full cost recovery of recently installed SCR technology, thereby impacting the utility's ROE.

Table 12 below summarizes the economic factors and levelized cost as a function of ROE. Figure 14 shows the change in levelized cost as a function of ROE for a 250-MW unit with 60 percent NO_X removal.

As shown in table 12, for every 2-percent increase in ROE, the current dollar levelized cost increases approximately 4.5 percent. Exhibit L contains the detailed calculations of economic factors and levelized cost summaries for a range of ROE values for the 250-MW plant.

Table 12
Levelized Cost for New SCR Vs. Return on Common Equity (ROE)
(250-MW Plant and 60 Percent NO_X Removal)

	Return on Equity (ROE)				
			Base Case		
	7%	9%	11%	13%	15%
Current Dollar Analysis					
Capital Charge Factor	0.132	0.141	0.150	0.160	0.169
O&M Levelization Factor	1.395	1.378	1.362	1.347	1.333
Constant Dollar Analysis					
Capital Charge Factor	0.100	0.108	0.116	0.124	0.133
O&M Levelization Factor	1.000	1.000	1.000	1.000	1.000
Current Dollar Analysis					
Levelized Cost (mills/kWh)	2.36	2.46	2.57	2.69	2.79
Levelized Cost ($/ton)	$2,295	$2,398	$2,500	$2,615	$2,720
Constant Dollar Analysis					
Levelized Cost (mills/kWh)	1.69	1.77	1.85	1.93	2.02
Levelized Cost ($/ton)	$1,646	$1,724	$1,802	$1,880	$1,968

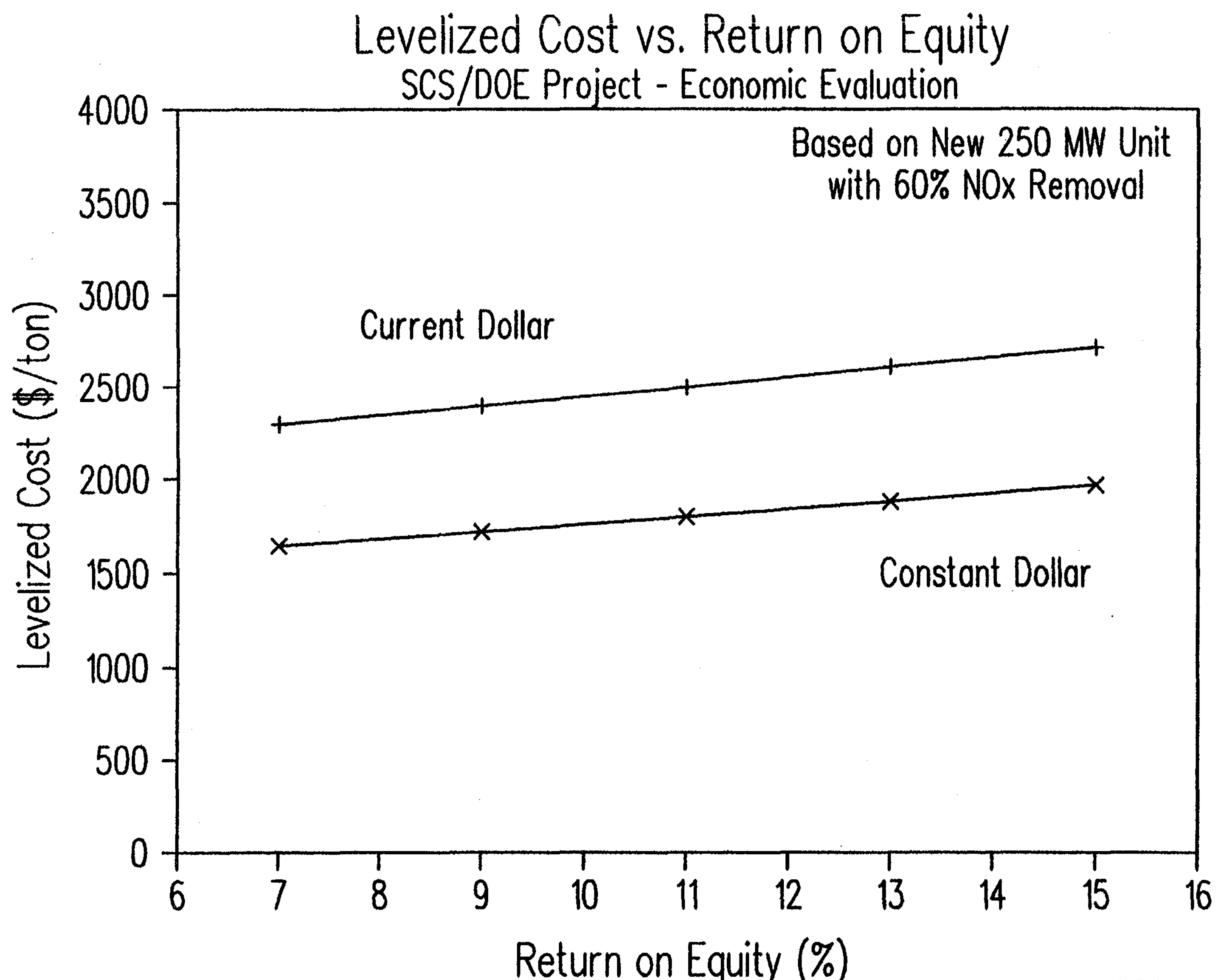

Levelized Cost vs. Return on Equity
SCS/DOE Project - Economic Evaluation
Based on New 250 MW Unit
with 60% NOx Removal
Current Dollar
Constant Dollar
Levelized Cost ($/ton)
4000
3500
3000
2500
2000
1500
1000
500
0
6
7
8
9
10
11
12
13
14
15
16
Return on Equity (%)
DOEROE.atb

Figure 14

3.6 Capital, O&M, and Levelized Cost for New SCR Vs. Catalyst Price (250-MW Plant Size and 60 Percent Removal)

Market price of catalyst can affect both the capital and O&M cost of SCR technology. The most recent experience in Germany during the 1980's resulted in catalyst market price variations ranging between $900/ft^3$ and $300/ft^3$ over an 8 to 10 year period. More recently in the U.S., one of the five new plants equipped with SCR realized a catalyst price of approximately $400/ft^3$.

To address the sensitivity of capital, O&M, and levelized cost to changes in the market price of catalyst, the catalyst price was varied by +/- $50/ft^3$. It is recognized that dynamic market forces may cause wider variation in prices than those assumed for this analysis. However, based on the comments of one of the participants of the project, $350/ft^3$ was quoted as a realistic, obtainable catalyst price based on current market conditions.

Table 13 shows the capital, O&M, and levelized cost vs. catalyst price for a new 250-MW unit. Varying the catalyst price +/- 12.5 percent (+/- $50/ft^3$) results in a change in levelized cost of only +/- 4 percent. Variable O&M is the most sensitive to changes in catalyst price since catalyst cost dominates this annual expense. Capital cost changed approximately 2 percent since the catalyst represents only 20 to 25 percent of the total process capital.

Table 13
Capital, O&M, and Levelized Cost for New SCR Vs. Catalyst Price
(250-MW Plant and 60 Percent NO_X Removal)

	Catalyst Price ($/ft^3$)		
		Base Case	
	$350	**$400**	**$450**
Total Capital Requirement	$13,040,000	$13,415,000	$13,777,000
Total Capital Requirement	$52/kW	$54/kW	$55/kW
First Year Fixed Operating Cost	$306,000	$312,000	$319,000
First Year Variable Operating Cost	$677,000	$733,000	$789,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	2.46	2.57	2.67
Levelized Cost ($/ton)	$2,398	$2,500	$2,602
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	1.78	1.85	1.92
Levelized Cost ($/ton)	$1,737	$1,802	$1,867

Exhibit M includes capital, O&M, and levelized cost summaries for $350/ft^3$ and $450/ft^3$ catalyst prices.

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4.0 Application of SCR Technology For a Retrofit Unit

The economic evaluations reported in prior sections of this report were focused on SCR installed on a new coal-fired facility. However, the majority of the near-term future U.S. SCR market may be in retrofit applications. The cost of implementing SCR technology is a topic of considerable debate in the present deliberations by the Ozone Transport Assessment Group (OTAG)* and in defining the U. S. Environmental Protection Agency's (EPA) proposed CAAA Title IV NO_X emission limits for Group 2 boilers, specifically cyclones. The boiler types, number of units per boiler type, and existing generating capacity for existing, base loaded duty, coal-fired units in the OTAG region alone are shown in table 14.

Table 14
Boiler Type, Number, and Generating Capacity in the OTAG* Region

Boiler Type	Number of units	Generating Capacity, MW
Wall-fired	315	94,327
Tangentially fired	315	112,000
Cyclone	77	22,329
Cell-fired	33	24,143
Wet-bottom	23	4,712
Roof-fired	29	3,111

* OTAG has proposed a 37-state nonattainment area encompasing the eastern part of the U.S.

Because of the considerable uncertainty and debate involving SCR retrofit cost for existing plants, SCS has completed a study to determine the cost and technical feasibility of retrofitting SCR technology to selected coal-fired generating units within the Southern electric system. While retrofit issues will vary from plant to plant and company to company, the results of this study reflect the typically wide range of retrofit costs due to site-specific issues encountered at those plants studied within the Southern electric system. It is recognized that the costs summarized in this study applicable to The Southern Company may or may not be indicative of other utility's installations due to boiler types, site constraints, and regulatory requirements.

4.1 General Retrofit Issues

From a technical perspective, based on the large number of worldwide applications of SCR on coal-fired boilers, SCR can be judged to be broadly applicable to a variety of boiler types and fuels. It is evident that the engineering issues associated with the design and retrofit of full-scale commercial SCR facilities have been and are being successfully addressed. SCR is more costly, however, when compared to combustion modifications, and exhibits poor economies of scale at smaller boiler sizes. Therefore, applicability and feasibility assessments must also consider site specific economic factors.

Table 15 provides a summary of factors affecting applicability and technical feasibility of SCR when applied to coal-fired retrofit applications.

Table 15
Summary of Factors Affecting Applicability and Technical Feasibility of SCR

FACTOR	COMMENTS
• Coal type and characteristics	• SCR primarily applied commercially to low-sulfur coal. Japanese experience is with clean, washed bituminous coal. European experience is with low-sulfur brown and black coal. Problem with alkali metal poisoning can occur with low-rank coals. Trace metal constituents in coal have potential to be catalyst poisons. Little operational experience on high-sulfur U.S. coals.
• Boiler size	• No limitations.
• Boiler age	• No technical limitations. As with any retrofit technology, remaining useful life affects economics.
• Boiler heat release limitations	• Not applicable to SCR.
• Capacity factor (CF) limitations	• No technical limitations. Prolonged low load helps space velocity of SCR as long as temperature maintained. Low CF hurts economics.
• Load profile	• Uncertain area for SCR. Japanese experience is with baseloaded units. European units will have more cycling duty. More data are needed in this area to assess site-specific impacts.
• Boiler firing type (PC v. cyclone, etc.)	• No technical limitations except that firing type affects flue gas NO_x level. High NO_x levels (>600 ppm) increases the capital cost of SCR. NO_x should first be reduced though combustion modifications, if possible.
• Boiler firing configuration	• Same as above. Tangentially fired boilers have slightly better homogeneous flue gas mixture and lower baseline NO_x than do wall-fired boilers.
• Boiler bottom type (wet v. dry)	• European experience has shown rapid catalyst deactivation on wet-bottom boilers due to fly ash metal vaporization and condensation on catalyst. Wet bottom applications will deactivate faster than dry bottom applications but new arsenic-resistant catalyst improves catalyst life. High-dust SCR widely applied to dry-bottom boilers.
• Geographic applicability	• No limitations, except as might affect shipping costs for NH_3 since major U.S. NH_3 source is U.S. Gulf Coast.
• SCR retrofit difficulty	• Because of the temperature range in which the SCR operates, retrofit feasibility is dictated by having adequate space available to locate large, heavy reactor between the economizer outlet and air preheater inlet.
• Boiler outlet flue gas temperature	• Flue gas temperature variation versus boiler load will dictate extent of economizer bypass required if operation over entire boiler load range is required. Requirement to bypass economizer at low loads will affect unit heat rate and may change heat absorption patterns in the boiler.
• Particulate collector requirements	• Affects type of SCR. "Cold-side" particulate collection (ESP or baghouse) requires high-dust SCR. "Hot-side" ESP allows choice of high- or low-dust SCR. Worldwide, high-dust SCR is the preferred approach.
• Air preheater requirements	• Air preheater physical features influence fouling potential due to ammonium salt formation. Possible degrade in performance due to higher pressure drop and flue gas mass flow. Review of heat transfer surface configuration, material, geometry, orientation, cleanability, temperature profile, leakage, and physical condition should be considered when assessing SCR impacts to existing plant.
• Raw material requirements	• Ammonia and catalyst. No other requirements.
• By-product market limitations	• No salable by-products. Ammonia slip could affect fly ash sales and increase landfill development costs.
• Thermal efficiency penalty	• Thermal penalty possible due to increased air preheater outlet gas temperature with high-sulfur applications. • If SCR is required to operate over wide boiler load range, thermal penalty will be incurred through lower boiler load range (as high as 1.0 percent). Extent of penalty is function of load dispatch.
• Waste disposal factors	• In most cases, spent catalyst is shipped back to catalyst vendor.
• Other factors	• High-dust, hot-side SCR must be considered in its effects on particulate collection efficiency and (if present) effects of slip NH_3 on a downstream FGD process. • Flue gas draft loss across SCR may dictate need for ID fan upgrade or balance draft conversion of boiler.

4.2 Specific Unit Technological Feasibility

The following plant descriptions are the result of inspections made for purposes of formulating a conceptual SCR retrofit design at selected plants within the Southern electric system. SCR performance requirements were estimated using combustion calculations based on field-collected low-NO_X burner acceptance test (or baseline test) information. Conceptual layouts were developed taking into account the retrofit difficulties at each site and the results of the catalyst suppliers' volume estimates. A material scope was then developed itemizing the major pieces of equipment. Where required, vendor quotes were obtained for required components. Much of the cost estimate was produced using SCS information. All of the units considered under this study are tangentially fired, pulverized coal boilers originally manufactured by Combustion Engineering.

4.2.1 Plant A

Plant A includes two tangentially fired, supercritical units nominally rated at 700 MW each. Each unit has a center wall dividing the furnace into two halves. There are six elevations of coal nozzles in each of the eight corners. The boiler is fired under balanced pressure. Both units are designed to deliver superheated steam at a rate of 5,044,992 lb/hr at turbine inlet conditions of 1000°F and 3500 psig. Both units have been retrofitted with low-NO_X firing systems featuring flame attachment coal nozzles, offset secondary air, and separated over fire air (SOFA).

The SCR arrangement reflects the difficulty in locating the reactors, due to a previously retrofitted cross-over duct for the "piggy back" cold-side precipitators added when the boilers were converted to balance draft operation. The SCR reactors are located directly to the rear of the boiler house, above the existing precipitator ductwork, in an attempt to avoid extensive modifications of the existing precipitator ductwork. This arrangement, as shown in figure 15, produces a "sidewinder" configuration (places the reactors toward opposite sides of the boiler house). This arrangement requires 90-degree horizontal turns in the SCR inlet and outlet duct, but positions the reactor closer to the boiler building with less overhang above the precipitators. Access to the back side of the boiler house wall is relatively unobstructed, but would require structural modifications to the boiler building crossbracing to allow for the ductwork. In addition, possible interference with the coal conveyors, located between Plant A and adjacent units, needs further investigation.

The sidewinder arrangement requires separate support structures for each reactor, but does not require penetration of the precipitator inlet plenum ductwork. A space truss would be used to individually support each SCR reactor, with the column spacing restricted by the available space between the boiler house and the precipitator. In addition, it may be necessary to modify or relocate major foundation, such as ash trenches, U-drains, and small equipment to accommodate this arrangement.

4.2.2 Plant B

Plant B includes two tangentially fired, supercritical units nominally rated at 880 MW each. Each unit has a center wall dividing the furnace into two halves. There are seven elevations of coal

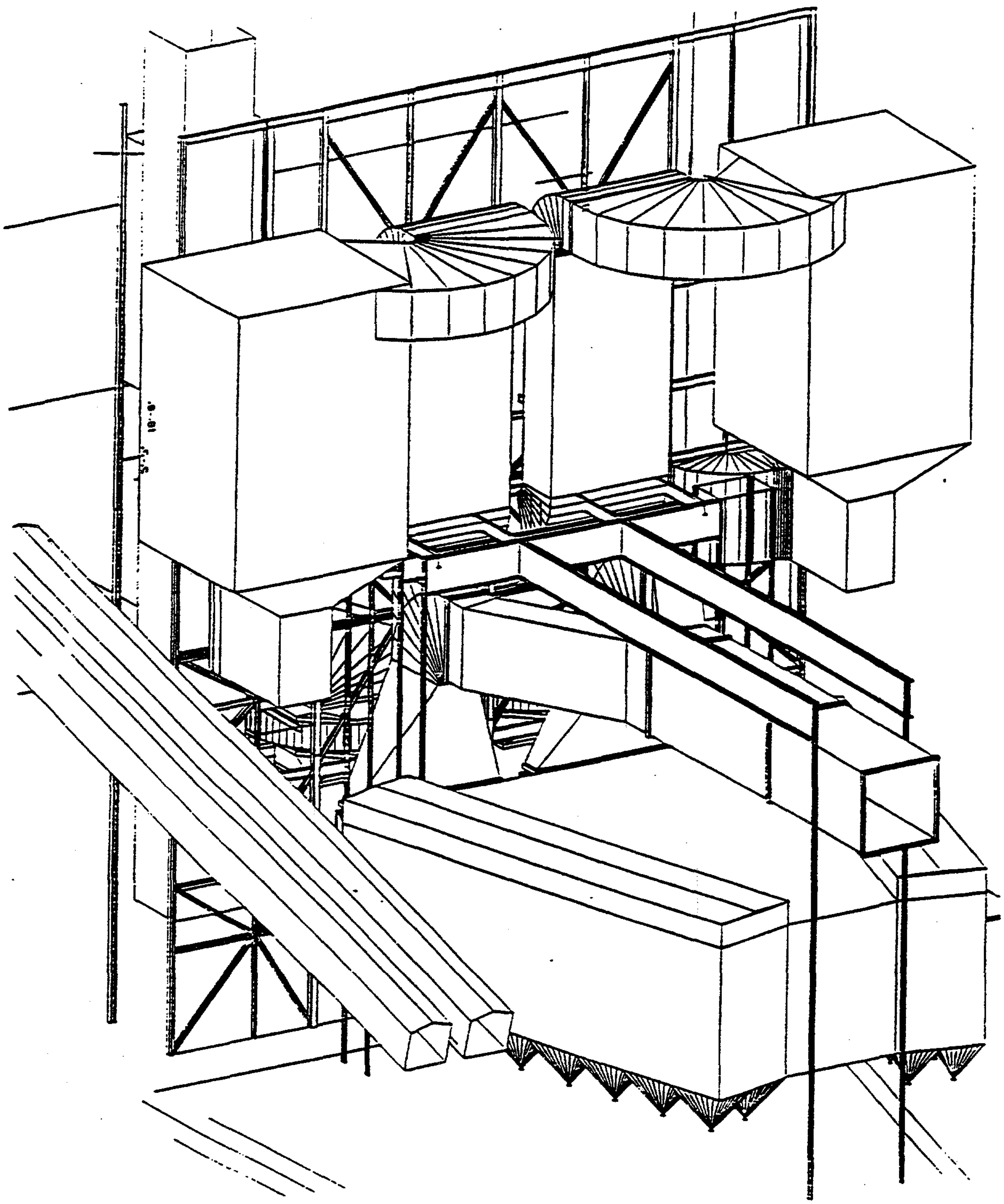


Figure 15
Perspective View of Retrofit SCR Arrangement for Plant A

nozzles in each of the eight corners. The boiler is fired under positive pressure. Both units are designed to deliver superheated steam at a rate of 6,351,470 lb/hr at turbine inlet conditions of 1000°F and 3500 psig. Both units have been retrofitted with low-NO_X firing systems featuring flame attachment coal nozzles, offset secondary air, and SOFA. There are two SOFA boxes, with two compartments each, on each of the eight corners. Each of the two compartments contains tilting air nozzles and individual damper control.

Because Plant B is limited in forced draft (FD) fan capacity during certain periods of the year, it is likely that a draft system upgrade will be required. No attempt has been made to determine if higher positive-pressure operation rather than balance draft conversion is technically feasible. In the absence of a detailed draft study, it is unclear whether or not the pressurized units would require balance draft conversion in order to retrofit SCR. The recent retrofit of an SCR at Public Service of New Hampshire's Merrimack Station illustrates that it is technically possible to retrofit an SCR on a pressurized unit without converting operation to balanced draft. However, this appears unlikely at Plant B due to the already limited capacity of the draft system. In order to bound the financial exposure, the cost estimate includes the balance draft option, which approximately doubles the cost to install SCR.

The proposed arrangement, as shown in figure 16, locates the SCR reactors directly to the rear of the boiler house, above the existing precipitator inlet ductwork. The unit will utilize two SCR reactors. The straight-back configuration of the reactors eliminates the need for horizontal turns in the SCR inlet and outlet ductwork. In figure 17, which shows the side elevation of this arrangement, the economizer outlet duct must turn upward upon exiting the building, thereby causing the reactors to be positioned further outward from the boiler building, above the precipitator inlet plenum duct. Once above the precipitator inlet ductwork, access to the back side of the boiler house wall is relatively unobstructed, but structural modifications will be required to the building crossbracing to allow for the SCR ductwork.

The two SCR reactors parallel the north/south centerline of the boiler building, an arrangement that allows for a common support structure for the two reactors. The proposed support structure for this arrangement consists of four towers supporting a frame common to both reactors. On the south end (toward the boiler building), the frame is supported by two towers and completely spans the precipitator inlet plenum duct. However, on the north end (toward the stack), it is necessary for two support towers to penetrate the plenum. Access to the SCR reactors would be provided on the south side of the reactors and tied into the boiler building.

An alternate plan would be to locate the SCR reactors on the roof of the boiler house. However, there is an existing monorail that extends out approximately 20 ft from the power house wall and runs parallel to the length of the boiler house. The ductwork to and from the SCR would have to be routed beyond the monorail. Because of this, it would not be practical to locate the SCR on the roof. The arrangement described above is located below the existing monorail, which could be used for catalyst additions.

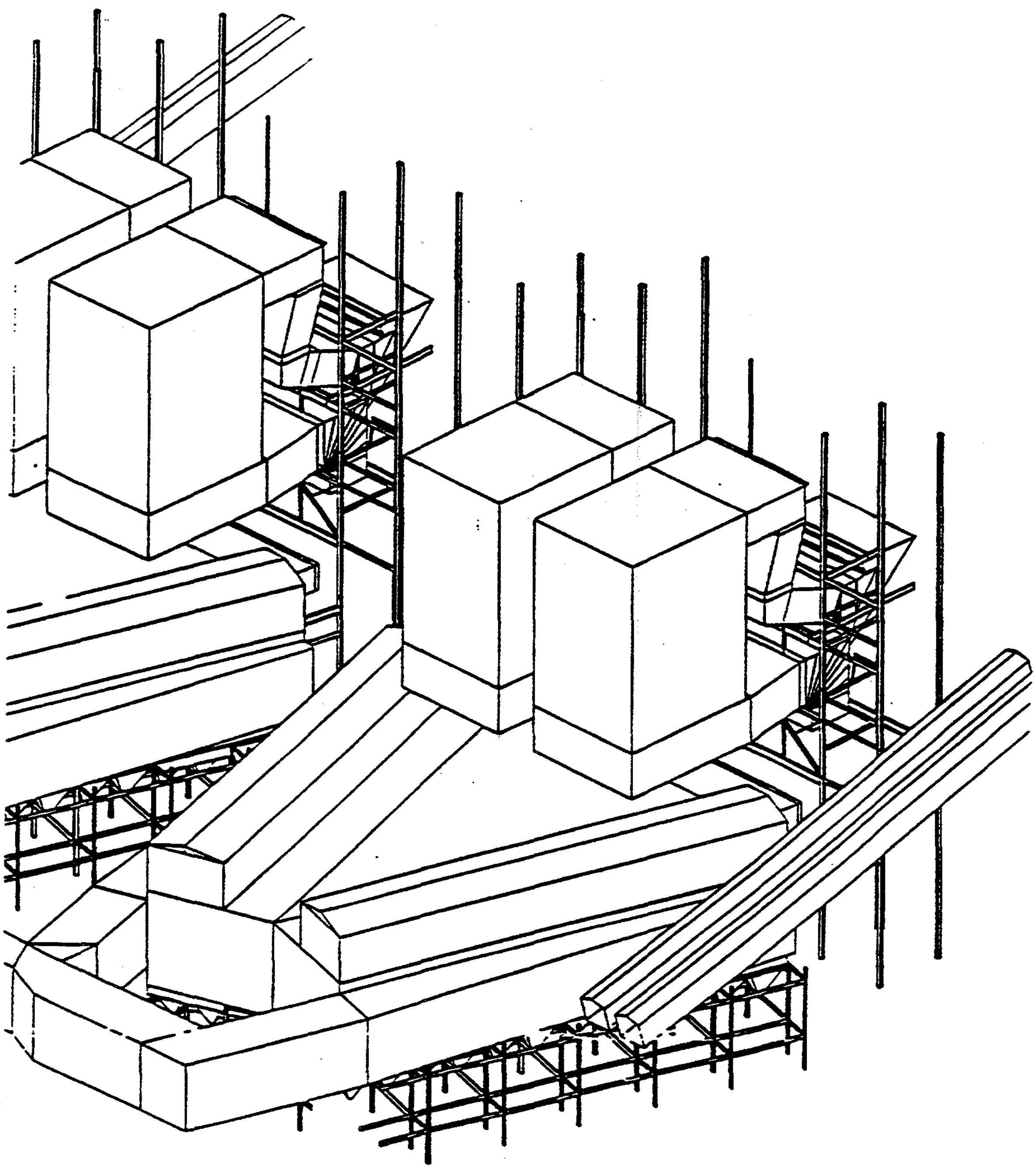


Figure 16
Perspective View of Retrofit SCR Arrangement for Plant B

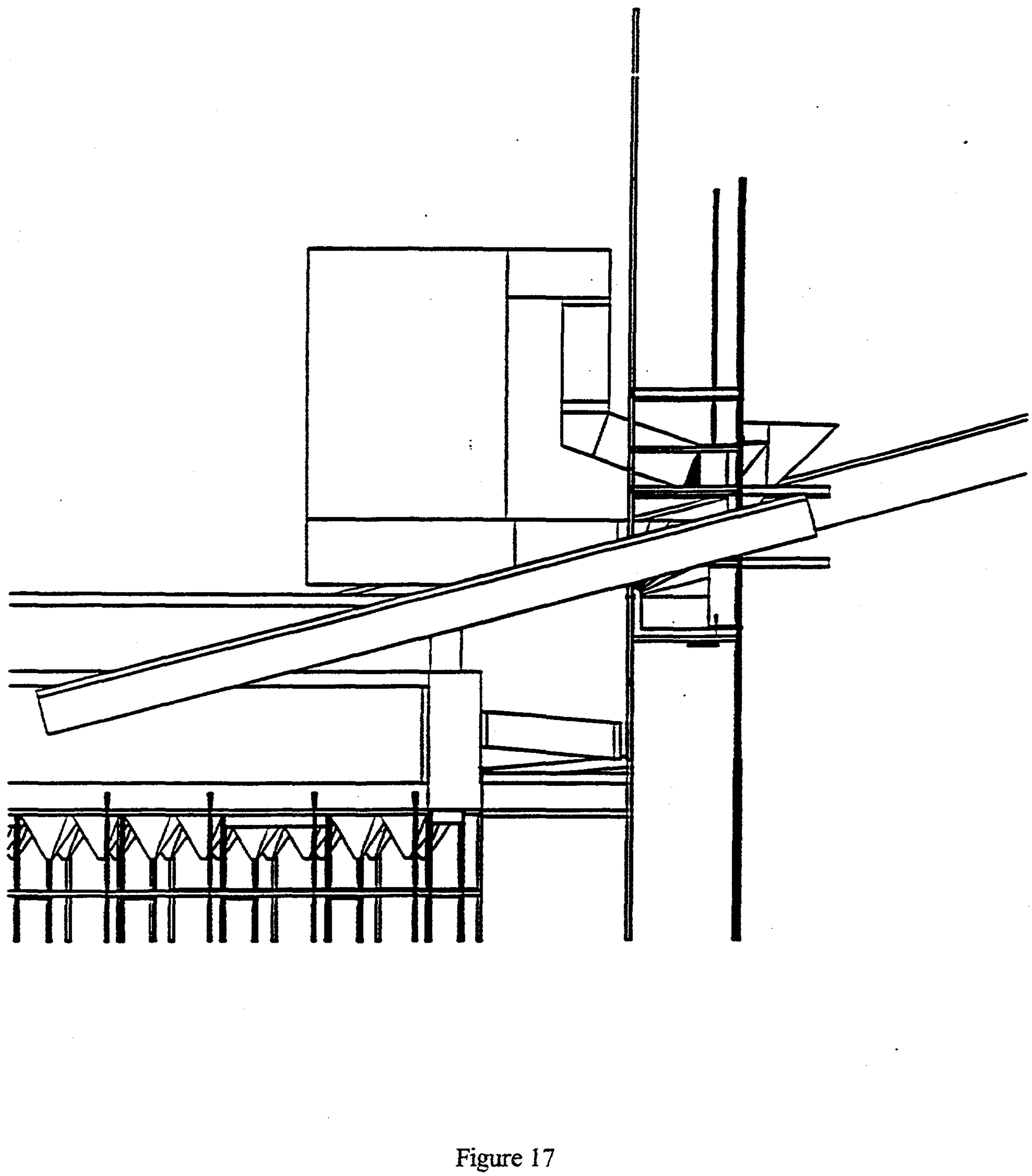


Figure 17
Side Elevation View of Retrofit SCR Arrangement for Plant B

4.2.3 Plant C

Plant C includes two tangentially fired, supercritical units nominally rated at 865 MW each. Each unit has a center wall dividing the furnace into two halves. There are seven elevations of coal nozzles in each of the eight corners. The boiler is fired under balanced pressure. Both units are designed to deliver superheated steam at a rate of 6,269,267 lb/hr at turbine inlet conditions of 1000°F and 3500 psig. One unit has been retrofitted with a low-NO_X firing system featuring low-NO_X coal nozzles, offset secondary air, and SOFA. There are two SOFA boxes, on each of the eight corners, with three compartments each of tilting air nozzles.

The proposed arrangement of the SCR reactors is similar to the location shown for Plant B (i.e., above the precipitator inlet plenum duct). Each unit is equipped with chevron-type electrostatic precipitators which have a low profile that provides a clear and unobstructed space above the inlet ductwork. The economizer outlet duct would exit the boiler room wall above elevation 855 ft. The SCR outlet duct would enter the building above elevation 834 ft. A space of approximately 20 ft between boiler house column line and the SCR reactor is needed to allow for moving replacement economizer sections up and into the boiler room.

The two SCR reactors parallel the north/south centerline of the boiler building, allowing an arrangement with a common support structure for the two reactors. The assumed support structure for this arrangement is similar to Plant B in that it will be necessary to penetrate the precipitator inlet plenum duct to support the SCR reactors. Access to the SCR reactors would be provided on the boiler house side, utilizing the existing monorail. Because the forced-draft fan intakes are located on the boiler house roof, the roof is not a viable location for the SCR reactors.

4.2.4 Plant D

Plant D includes two tangentially fired, subcritical units nominally rated at 245 MW each. Each unit has a center wall dividing the furnace into two halves. There are five elevations of coal nozzles in each of the eight corners. The boiler is fired under balanced pressure. Both units are designed to deliver superheated steam at a rate of 1,734,000 lb/hr at turbine inlet conditions of 1000°F and 2400 psig. Both units have been retrofitted with a low-NO_X firing system which features a split-flame, wall-fired low-NO_X burner technology into a corner-fired tilting burner technology. A close coupled overfire air compartment is located above the top coal elevation.

Based on the results of the study, retrofit of SCR would be difficult at these units due to the existing location of previously retrofitted precipitators. The precipitators are elevated over an active railroad spur, which forced the entire precipitator assembly to be displaced vertically upward. The precipitator outlet ductwork is routed over the top of the precipitator, up the back side of the boiler building, and up to the roof. As a result, the precipitators and ductwork effectively block the back side of the boiler house where ductwork tie-ins between the economizer outlet and the air preheater inlet would be required in order to add SCR.

The proposed location of the SCR reactors is on either side of the existing boiler house, as shown in figures 18 and 19. This arrangement (opposite hand for each unit) produces a "sidewinder"

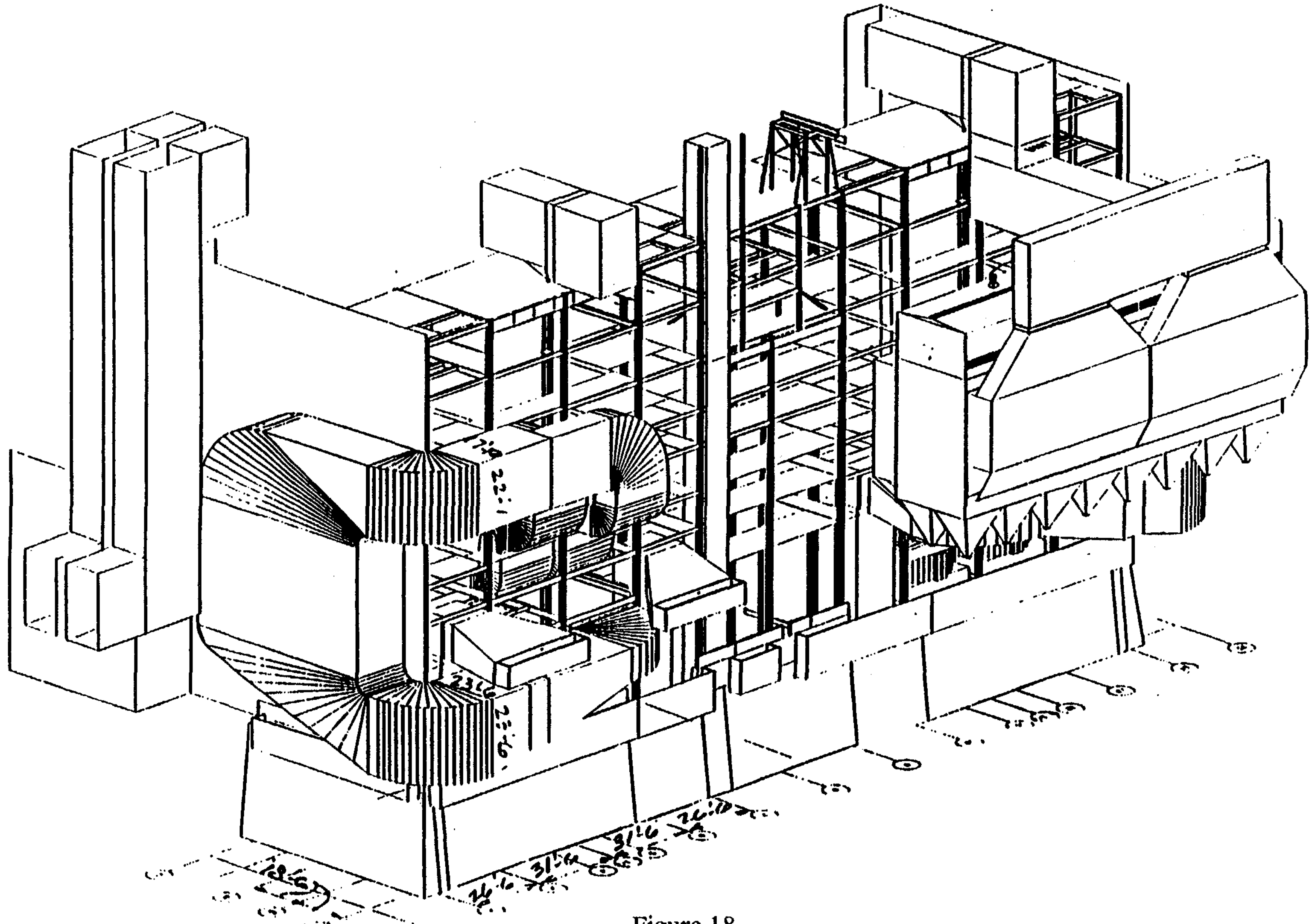


Figure 18
Perspective View of Retrofit SCR Arrangement for Plant D
(Electrostatic Precipitator (ESP) Removed for Clarity)

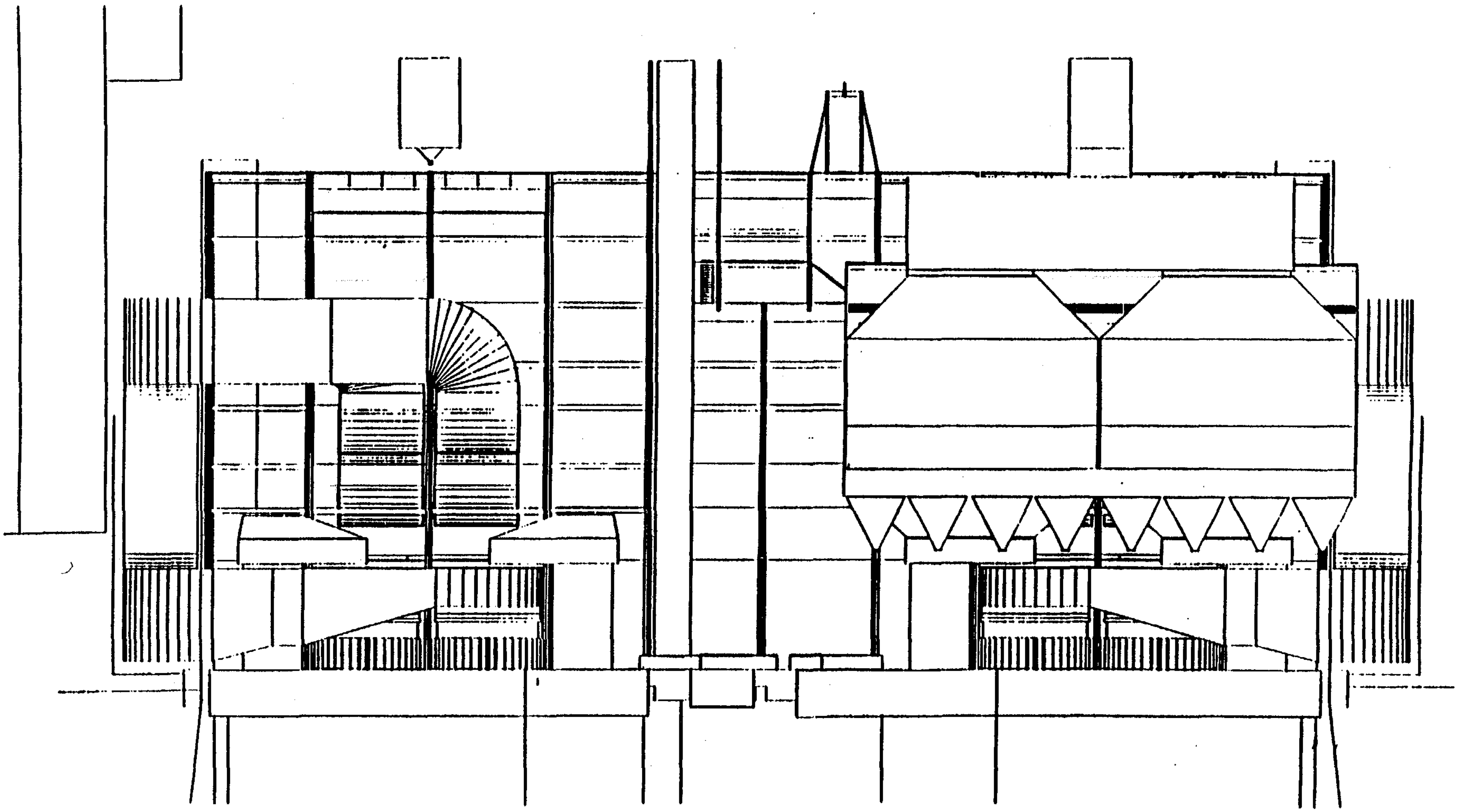


Figure 19
Front Elevation View of Retrofit SCR Arrangement for Plant D
(Electrostatic Precipitator (ESP) Removed for Clarity)

configuration, which places the reactors on opposite sides of the boiler house. The economizer outlet duct would turn up and exit the boiler room wall above elevation 831 ft. Due to the very restricted space between the boiler house wall and the precipitator, approximately 19 ft, a vertically oriented narrow duct is proposed which would combine the two flue gas ducts to a single SCR reactor. While the reactor, as shown in the figures, is wrapped around the boiler building, this is not a requirement, and could project parallel to the existing railroad track beneath the precipitators. The SCR exit duct would reenter the boiler house below elevation 820 ft, again having to fit through a very restricted space between the boiler house wall and the precipitator. As seen in the figures, this return duct is likely to block access to the existing road located under the precipitator ductwork.

The most difficult aspect of SCR retrofit at these two units is the tie-in points at the economizer outlet and air preheater inlet. The conceptual arrangement requires several 90-degree turns in the SCR inlet and outlet ductwork to get out of the boiler house. It is thought that an alternate, more optimized, ductwork routing could be achieved with a more detailed study. One alternative may allow routing of the SCR inlet duct inside the boiler house, running parallel to the back wall. This would allow penetration of the SCR inlet duct on the side of the existing boiler house wall. However, this would block several bays inside the boiler house. The SCR return duct would require that the existing flue gas conditioning equipment be removed to make room for the new ductwork.

While ID fan allowances are included in the estimate, these units currently utilize retrofitted two-speed ID fans. Normal practice is to run the ID fan on lower speeds most of the time. Therefore, it may be possible to accommodate the additional SCR draft loss with minimal modifications to the existing ID fan.

4.2.5 Plant E

Plant E includes three tangentially fired, subcritical units nominally rated at 100 MW and two tangentially fired, subcritial units nominally rated at 125 MW. Each boiler has four elevations of coal nozzles in cast iron windboxes located in each of the four corners. The boilers are fired under balanced pressure. None of the 100-MW units have been retrofitted with low-NO_X firing systems. The two 125-MW units have been retrofitted with low-NO_X firing systems featuring flame attachment nozzles, offset secondary air, and two elevations of close coupled overfire air.

The five Plant E units are similar to the two Plant D units in that the electrostatic precipitator effectively blocks access to the tie-in point between the boiler economizer exit and the air preheater inlet. This is exacerbated by the fact that the air preheaters are located below grade elevation, while the precipitators are located above grade elevation, blocking well over half of the back side of the boiler building. The precipitators are also located very close to the boiler building, which complicates the ability to pass a duct between the precipitator and the boiler house. Since there are multiple adjacent units at Plant E (units arranged in a side-by-side power block), access to the interior units will complicate the retrofit. Space is available on the boiler house roof to accommodate an SCR reactor having preliminary dimensions of 530 square ft cross-sectional area by 30 ft depth for each unit.

The conceptual design includes rerouting the existing duct from the economizer to the air preheater by replacing the 90-degree elbow down to the air preheater with a 90-degree elbow up toward the roof. The supply duct from the economizer outlet to the SCR would run from the economizer inside the boiler house, to an approximate elevation of 787 ft, until the precipitator located outside the boiler house wall is cleared. The duct would then be run outside the boiler house up to the SCR. The maximum dimension for the supply duct, while inside the boiler house, would be 18 ft 11 in. by 3 ft 10 in. The duct size, once outside the boiler house wall, is essentially unrestricted.

The return duct will run posterior to the supply duct and enter the boiler house wall below the supply duct, then elbow down to the existing transition piece on the air preheater. The return duct from the SCR to the air preheater can be routed outside the boiler house wall to approximate elevation 785 ft, at which point the duct can penetrate the boiler house wall and run inside the boiler house to the air preheater. The maximum dimension for the return duct, once inside the boiler house, is 18 ft 11 in. by 3 ft 8 in. The duct located outside the boiler house wall is unrestricted. Preliminary observations indicate that the transition duct from the air preheater to the new duct (on all units) could remain; however, turning vanes most likely will be required.

Units at Plant E, under the configuration described above, will require some major structural steel modifications to accommodate the duct run. Additionally, there are several large diameter ash pipes and roof drain pipes that will require relocation.

Additional retrofit difficulty also exists because all five units share a common chimney. Flue gas ductwork from the 100-MW units are combined, entering on one side of the stack. Ductwork from the 125-MW units are combined, entering on the opposite side of the stack. Because the units share a common stack there is little potential for rearranging or relocating components to make room for the SCR related equipment behind the boiler house.

4.2.6 Plant F

Plant F includes two tangentially fired, subcritical units nominally rated at 350 MW each. There are five elevations of coal nozzles in each of the four corners. The boiler is fired under positive pressure. Both units are designed to deliver superheated steam at a rate of 2,568,331 lb/hr at turbine inlet conditions of 1000°F and 2400 psig. Both units have been retrofitted with low-NO_X firing systems featuring flame attachment coal nozzles, offset secondary air, and SOFA. There are two SOFA boxes, with two compartments each, on each of the four corners. Each compartment contains tilting air nozzles and individual damper control.

The arrangement of the electrostatic precipitators at Unit F would allow access through the back of the boiler house wall to the boiler economizer exit and air preheater inlet. Two locations were identified for the SCR reactor.

The first location indicates that the boiler house roof would have sufficient space for the SCR reactor. Alternatively, the SCR reactors could be located on structural towers over the existing electrostatic precipitator inlet ductwork and the precipitator itself.

The supply duct could be routed by extending the existing elbow at the economizer to outside the boiler house and turning the elbow up to run the duct to the SCR. This would require the use of turning vanes because of the restrictive height between the economizer and the air preheater of less than 20 ft.

The return duct from the SCR to the air preheater could be routed outside the boiler house, posterior to the supply duct, and then penetrate inside at an elevation of approximately 835 ft. The transition piece from the air preheater to the duct run probably would not need to be adjusted. Turning vanes would be required to allow for the restrictive space to turn into the air preheater transition duct. The dimension of the duct outside the boiler house is unrestricted. Some structural steel modification would be required to accommodate the revised duct for both the supply and return.

In addition to moderate retrofit difficulty due to ductwork and reactor location, a balanced draft conversion on both units would likely be required in order to accommodate the increased draft loss due to the SCR. The addition of ID fans and balanced draft conversion are reflected in the capital cost and increase considerably the cost of adding SCR to these units.

4.3 Cost Methodology

Retrofitting SCR to an existing plant requires higher capital cost than a new plant because of the need to integrate the process into existing plant systems and accommodate site-specific physical and operational constraints. In addition, when compared to new boilers, higher inlet NO_X from existing boilers will necessitate greater catalyst volumes and, therefore, larger reactor sizes in an application where there is likely to be less space available due to retrofit difficulties. When compared with new installations, necessary costs for upgrade or new ID fans, gas handling equipment, and balance-of-plant modifications are often not included in literature estimates of SCR retrofit cost. These costs are included in this analysis.

This section describes the economic considerations and methods used to evaluate SCR as a potential retrofit NO_x control technology for selected units included in this study.

4.3.1 Economic/Technical Assumptions

The following technical and economic assumptions were used in this retrofit study:

- The retrofit study considered tangenially fired units with boiler sizes ranging from 100 MW to 955 MW.
- SCR design removal efficiencies of 40 percent, 60 percent, and 80 percent were estimated.
- Catalyst life guarantee was assumed to be 2 years (16,000 hours).
- Ammonia slip was assumed to be 2 ppmv measured on a dry basis.

- Actual inlet NO_x concentrations for the existing units were used as the basis of the SCR design. The inlet NO_x ranged from 0.55 to 0.40 lb/MBtu and represent tangentially fired units both with and without low NO_x combustion modifications.

- Similar to a new unit, it was assumed that the required operation of the SCR was over a boiler load range of 35 percent to 100 percent.

- An SO_2 to SO_3 oxidation rate of 1.0 percent was assumed due to a lower sulfur coal. (In the case of the new unit analysis utilizing a nominal 3 percent sulfur fuel, the lowest possible oxidation rate of 0.75 percent was desired to minimize the collateral impacts of high SO_3 concentrations. However, in the case of the retrofit analysis where a nominal 1.5 percent sulfur fuel is used, it was thought that a slightly higher oxidation rate of 1 percent could be tolerated in an effort to maximize space velocity for a given NO_x reduction, resulting in an overall reduction in SO_3 concentration at the SCR outlet compared to the new unit case.)

- A 15 year life was assumed. Units which were currently scheduled to retire prior to the end of the study are assumed to be extended through the end of the study period.

- All costs are expressed in 1996 dollars.

- Heat input to each boiler is the 15-year average annual total Btu projected burn for the unit before the SCR was added.

- The velocity, ammonia, and temperature distribution requirements are assumed to be identical to the new unit analysis shown in table 3.

    - The NO_x rate for each unit is assumed to be the rate at the unit's operating maximum.

    - The NO_x rates are assumed not to affect the economic dispatch of the units.

- Eastern low-sulfur coal (nominally 1 to 1.5 percent sulfur) was assumed to be the fuel for all units.

- Increases in station service and/or heat rate impacts are valued using SCS's Worth of Unit Improvement (WUI) methodology. The WUI is a methodology for valuing the additional station service consumed and the heat rate impacts due to the addition of a particular NO_x control technology. Calculations are specific to the Southern electric system and take into account each unit's total fuel cost, O&M cost, unit capacity factors, and hours of operation at various output levels for each unit. Therefore, depending on the particular unit, the value of station service will be greatest at lower loads when the unit is less efficient, and smallest at higher loads when the unit is operating at its maximum efficiency. The WUI method also considers the value impact to the system due to changes in system hourly production cost and capacity deferment.

- The reactor assumed for each application in this study utilizes a hot-side, high-dust configuration with three catalyst layers plus a flow straightener layer. The flow straightener layer consists of fabricated modules of 2 in. x 2 in., 16-gauge mild steel tube approximately 18 inches in length.

- The design includes one vertical, downflow reactor per air preheater. Therefore, on units where a split train draft system utilizes two air preheaters, two SCR reactors are included in the estimate.

- The reactor is equipped with an economizer bypass to permit SCR operation at lower boiler loads.

- All catalyst layers include steam sootblowers. The sootblower design is identical to those used in the SCR demonstration project facility.

4.3.2 Capital Costs

Capital costs for the SCR include all ammonia storage and injection equipment, reactor with initial catalyst charges, allowance for ID fan upgrade (or balanced draft conversion cost), allowance for air preheater upgrade, erection, indirects, AFUDC, engineering, temporary construction facilities, utility company overheads, and field supervision.

4.3.3 O&M Costs

Fixed O&M costs include estimates of maintenance material and labor, operating labor, and administration/support labor. Variable O&M captures ammonia consumption and catalyst replacement costs. In addition, estimates of incremental station service costs due to SCR and minimum SCR load point for calculating thermal efficiency (heat rate) penalty are included.

4.4 Summary of Capital and O&M Costs for Each Unit

Table 16 shows the capital, O&M, and current dollar levelized costs for selected units. The SCR retrofit costs vary from $1,541/ton to $7,419/ton depending on NO_x removal percentage, unit size, inlet NO_x concentration, utilization (capacity factor), and capital and O&M costs. Even though the capital cost (in dollars) increases as plant size increases, lower levelized costs are achieved when SCR is applied to larger, higher utilized units such as Plants A, B, and C. This is due to economies of scale and the fact that the quantities of NO_x removed are greater on larger units.

All of the units shown in table 16 have been retrofitted with some type of combustion modifications to lower the NO_x concentration prior to the retrofit of SCR. While some capital cost savings can be achieved in the SCR by lowering the inlet NO_x , the resulting levelized cost is higher due to fewer tons removed when compared to an SCR retrofit on an uncontrolled unit.

Table 16
Capital, O&M, and Levelized Cost for Retrofit of SCR to Selected Southern Company Units

		Plant A	Plant B	Plant C	Plant D	Plant E	Plant F
Power Plant Attributes	Units						
Plant Capacity	MW	700	880	880	265	100	350
Average Annual Heat Input	MBtu	43,137,998	57,714,319	54,107,012	9,848,867	3,627,034	17,746,062
Calculated Capacity Factor	%	74%	81%	75%	43%	33%	55%
Evaluation life	years	15	15	15	15	15	15
40 Percent Removal							
SCR Removal Efficiency	%	40	40	40	40	40	40
Emission without SCR	lb/MBtu	0.41	0.43	0.41	0.37	0.45	0.32
Emission with SCR	lb/MBtu	0.25	0.26	0.25	0.22	0.27	0.19
Tons of NOx removed	ton/yr	3537	4963	4437	729	326	1136
CAPITAL COST							
Capital Cost ($) *(note 1)*		$41,933,000	$110,795,000	$48,131,000	$19,778,000	$8,112,000	$37,639,000
Capital Cost ($/kw)		$60	$126	$55	$75	$81	$108
ANNUAL OPERATING AND MAINTENANCE COST							
Fixed and Variable Operating Costs		$2,062,000	$2,453,000	$2,453,000	$1,116,000	$757,000	$1,300,000
WUI Operating Costs *(note 4)*		$601,000	$691,000	$708,000	$304,000	$257,000	$767,000
LEVELIZED COST							
Current Dollar Levelized Cost	$/ton	$2,700	$4,181	$2,498	$6,440	$7,419	$7,220
60 Percent Removal							
SCR Removal Efficiency	%	60	60	60	60	60	60
Emission without SCR	lb/MBtu	0.41	0.43	0.41	0.37	0.45	0.32
Emission with SCR	lb/MBtu	0.16	0.17	0.16	0.15	0.18	0.13
Tons of NOx removed	ton/yr	5306	7445	6655	1093	490	1704
CAPITAL COST							
Capital Cost ($) *(note 1)*		$45,295,000	$114,440,000	$52,019,000	$21,336,000	$8,747,000	$39,188,000
Capital Cost ($/kw)		$65	$130	$59	$81	$87	$112
ANNUAL OPERATING AND MAINTENANCE COST							
Fixed and Variable Operating Costs		$2,461,000	$2,949,000	$2,949,000	$1,283,000	$836,000	$1,513,000
WUI Operating Costs *(note 4)*		$630,000	$732,000	$744,000	$317,000	$263,000	$782,000
LEVELIZED COST							
Current Dollar Levelized Cost	$/ton	$1,991	$2,946	$1,848	$4,703	$5,346	$5,108
80 Percent Removal							
SCR Removal Efficiency	%	85	80	80	80	80	80
Emission without SCR	lb/MBtu	0.41	0.43	0.41	0.37	0.45	0.32
Emission with SCR	lb/MBtu	0.06	0.09	0.08	0.07	0.09	0.06
Tons of NOx removed	ton/yr	7517	9927	8874	1458	653	2271
CAPITAL COST							
Capital Cost ($) *(note 1)*		$47,935,000	$116,030,000	$55,112,000	$22,519,000	$9,223,000	$39,762,000
Capital Cost ($/kw)		$68	$132	$63	$85	$92	$114
ANNUAL OPERATING AND MAINTENANCE COST							
Fixed and Variable Operating Costs		$3,099,000	$3,714,000	$3,714,000	$1,613,000	$1,049,000	$1,903,000
WUI Operating Costs *(note 4)*		$641,000	$746,000	$759,000	$322,000	$265,000	$788,000
LEVELIZED COST							
Current Dollar Levelized Cost	$/ton	$1,559	$2,325	$1,541	$3,917	$4,502	$4,071

Notes:
1. Capital cost estimate includes the cost of balance draft conversion for Plant B and Plant F.
2. Levelized cost based on 15 year life, 9.245% cost of capital, and 3.04% escalation.
3. All values shown in 1996 dollars.
4. Worth of Unit Improvement (WUI) methodology is used to value the heat rate impacts and additional station service requirements.

Figure 20 shows a comparison of levelized cost vs. NO_x removal efficiency for a new and retrofit SCR installation applied to a 250-MW unit designed for 60 percent removal. While the retrofit unit levelized cost is higher than the new unit, the difference is fairly small. The difference is primarily due to higher capital cost of the retrofit installation, since the inlet NO_x concentrations for the retrofit (0.40 lb/MBtu) and the new unit (0.35 lb/MBtu) are similar and approximately the same number of tons of NO_x are removed.

While figure 20 shows little difference in levelized costs, the capital cost differences between the new SCR installation and the retrofit SCR installations are large. For a 60 percent removal design, the estimated retrofit cost is approximately 51 percent greater than the estimated new cost installation. (This comparison is highly site specific and actual retrofit costs may be higher or lower than those presented here) Table 17 shows the capital cost difference between a new and retrofit SCR installation.

Table 17
Capital Cost Differences for New and Retrofit SCR Installations
(250-MW Plant Size)

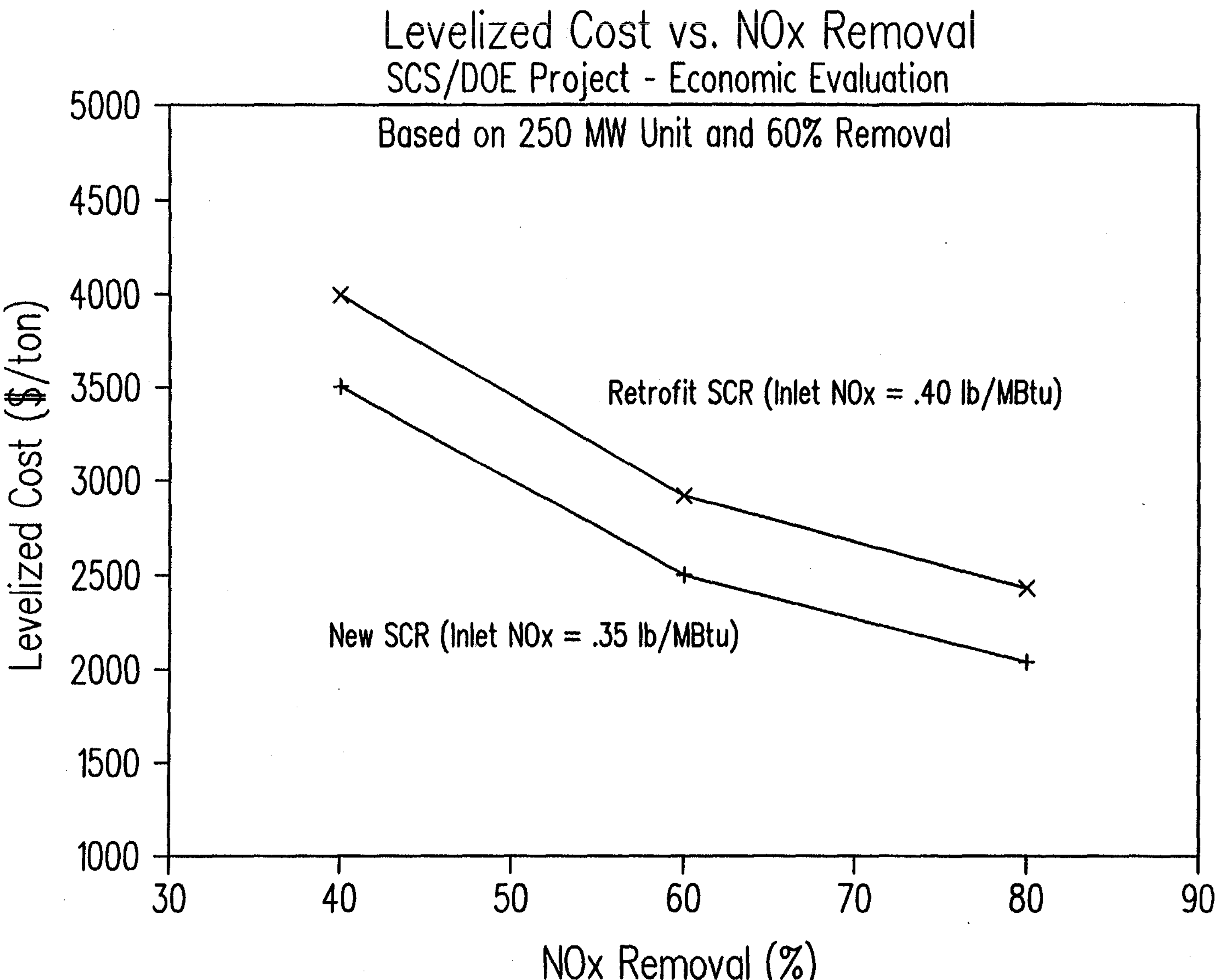
	NO_X Removal Efficiency		
	40%	**60%**	**80%**
New SCR Installation			
Total Capital Requirement	\$12,974,000	\$13,415,000	\$14,142,000
Total Capital Requirement	\$52/kW	\$54/kW	\$57/kW
Retrofit SCR Installation			
Total Capital Requirement	\$18,800,000	\$20,281,000	\$21,403,000
Total Capital Requirement	\$75/kW	\$81/kW	\$86/kW

As seen from table 17 and figure 20, technical and economic assessment of SCR must be based on both the cost effectiveness and the first cost (capital cost cash flow) of the proposed installation.

4.5 Extrapolation of Data to High Inlet NO_x Cases

At the request of the DOE, the Southern Company specific retrofit cost data were extrapolated to high inlet NO_x conditions in an effort to represent many of the boilers in the OTAG region.

Due to the fact that Southern Company's boiler population is predominantly wall-fired and tangentially fired boilers, there was has been no corporate need to rigorously define the capital and operating cost at high inlet NO_x concentrations indicative of cell burner and cyclone fired boilers. However, it is recognized that these high emitting boiler types may face more stringent



Levelized Cost vs. NOx Removal
SCS/DOE Project - Economic Evaluation
Based on 250 MW Unit and 60% Removal
5000
4500
4000
3500
3000
2500
2000
1500
1000
Levelized Cost ($/ton)
Retrofit SCR (Inlet NOx = .40 lb/MBtu)
New SCR (Inlet NOx = .35 lb/MBtu)
30
40
50
60
70
80
90
NOx Removal (%)
RETREM.atb

Figure 20

NO_x control requirements in the future. Therefore, analysis of high emitting boilers is presented in this report for information purposes.

The results presented in this section are subject to the following caveats:

1. The estimate is based on a 250-MW unit with a retrofitted SCR designed for 60 percent removal. The retrofit difficulty is representative of plant configurations in the OTAG region.

2. Best efforts were made to adjust the capital and O&M costs for increasing inlet NO_x conditions. Specifically, the space velocity (catalyst volume), reactor height, and ammonia consumption are the primary process variables adjusted. These adjustments were based on factors obtained from several catalyst suppliers.

3. This comparison, while valid for screening purposes, is generic in nature and does not preclude the need to perform site specific cost evaluations, particularly for high NO_x emitting boilers.

The result of the extrapolated data shown in figure 21 indicates a significant trend of decreasing levelized cost with increasing inlet NO_X concentration, highlighting a key difference in cost effectiveness between a lower emitting boilers (or boilers which have been controlled with combustion modifications prior to the SCR) and higher emitting, uncontrolled boilers.

For a given removal percentage, 60 percent in this case, the higher emitting boilers result in a greater number of tons removed when compared to the lower emitting boilers. The annual tons of NO_x removed range from 1247 to 9975 for 0.30 lb/MBtu and 2.4 lb/MBtu inlet NO_x concentrations, respectively.

Note that the constant dollar levelized cost of \$534/ton at 2.4 lb/MBtu inlet NO_x condition approaches the recently reported levelized cost of \$404/ton for a 65 percent NO_x reduction system recently reported by Public Service of New Hampshire at their Merrimack station. (Differences between the two values are mainly attributable to the study retrofit cost of \$87/kW verses Merrimack's recently reported capital cost of \$56/kW, and the difference in 60 percent removal verses 65 percent removal.) Results shown in Figure 21 also compare favorably with recently published levelized cost from Public Service Electric and Gas Company's Mercer Generating Station.

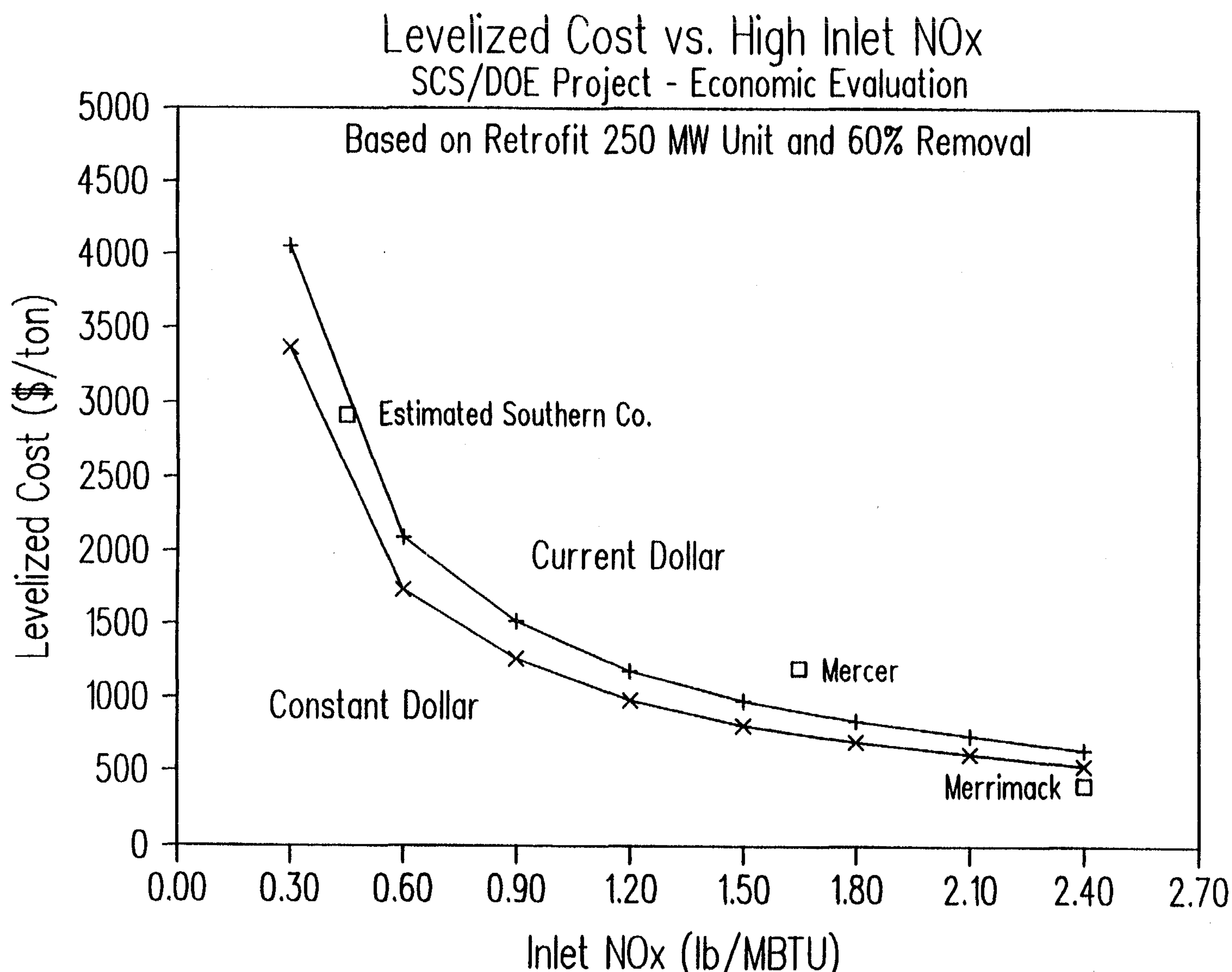

Levelized Cost vs. High Inlet NOx
SCS/DOE Project - Economic Evaluation
Based on Retrofit 250 MW Unit and 60% Removal
Levelized Cost ($/ton)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Estimated Southern Co.
Current Dollar
Constant Dollar
Mercer
Merrimack
0.00
0.30
0.60
0.90
1.20
1.50
1.80
2.10
2.40
2.70
Inlet NOx (lb/MBTU)
RETNOIN.atb

Figure 21

5.0 References

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Exhibit A

Economic Evaluation Parameters

EXHIBIT A
ECONOMIC EVALUATION PARAMETERS

PROJECT TITLE: DOE SCR Project - Economic Evaluation

Economic Assumptions	Units	Value
Cost of debt	%	8.5
Dividend rate for preferred stock (pre-tax)	%	7.0
Dividend rate for common stock (pre-tax)	%	11.0
Debt ratio, % of total capital		50.0
Preferred stock, % of total capital		15.0
Common stock, % of total capital		35.0
Income tax rate	%	38.0
Investment tax credit	%	0.0
Property taxes & insurance	%	3.0
Inflation rate	%	3.0
Discount rate (with inflation)	%	9.150
Discount rate (without inflation)	%	5.971
Escalation of raw materials above inflation	%	0.0
Construction period (choose 1-6)	Years	1.5
Allowance for funds during construction [a]	%	1.91
Construction downtime	Days	0
Remaining life of power plant	Years	30
Year for input cost data		1996
Year for costs presented in this report		1996
Royalty allowance (based on Total Process Capital)	%	0
Capital charge factor & O&M cost levelization factor		
Current dollars:		
Capital charge factor		0.150
O & M cost levelization factor		1.362
Constant dollars:		
Capital charge factor		0.116
O & M cost levelization factor		1.000
Power plant capacity factor	%	65
Sales tax rate	%	5.0
Cost of freight for process equipment	%	2.0
Sales tax plus freight	%	7.0
General facilities, % of total process capital		2.0
Engineering & home office fees, % of total process capital		8.0

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[a] Represents the time value of funds used for construction based on an interest rate equal to weighted cost of capital assuming 3.0 % inflation rate and 9.150 % discount rate.

Calculation of Capital Charge Factor and O&M Cost Levelization Factor

	Units	Value	Equivalent Value	Without Inflation
Cost of debt	%	8.5	0.085	0.053
Dividend rate for preferred stock (pre-t	%	7	0.070	
Dividend rate for common stock (pre-t	%	11	0.110	
Debt ratio, % of total capital		50.0	0.50	
Preferred stock, % of total capital		15.0	0.15	
Equity Ratio, % of total capital		50.0	0.50	
Income tax rate	%	38.0	0.38	
Investment tax credit (ITC)	%	0.0	0.00	
Property taxes & insurance	%	3.0	0.03	
Inflation rate	%	3.0	0.03	
Discount rate (with inflation)	%	9.15		
Discount rate (without inflation)	%	5.971		
Remaining life of power plant	Years	30		
Tax recovery period	Years	30		
Straight line tax depreciation	%/yr	3.333	0.0333	
Equity cost	%	9.800	0.0980	0.0660
Book depreciation rate net of ITC	%/yr	3.333	0.0333	
Book value net of ITC	%	100	1.00	

m = tax recovery life, years
n = book life, years

Current Dollars (With Inflation)

Year	Present Value Factor v	Annuity Factor a	Tax Depreciation Rate td	Deferred Income Tax dt	Taxes Paid tp	Year-by-Year Carrying Charge CC	Present Value of Carrying Charge	Cumulative Present Value CC Vf,m,n	Levelized CC Pf,m,n
1	0.916170	0.916170	0.033333	0.000000	0.030032	0.184866	0.169368	0.169368	0.184866
2	0.839368	1.755539	0.033333	0.000000	0.029031	0.180815	0.151770	0.321138	0.182929
3	0.769004	2.524543	0.033333	0.000000	0.028030	0.176763	0.135932	0.457070	0.181051
4	0.704539	3.229082	0.033333	0.000000	0.027029	0.172712	0.121683	0.578753	0.179231
5	0.645478	3.874560	0.033333	0.000000	0.026028	0.168661	0.108867	0.687620	0.177470
6	0.591368	4.465927	0.033333	0.000000	0.025027	0.164610	0.097345	0.784965	0.175768
7	0.541794	5.007721	0.033333	0.000000	0.024026	0.160559	0.086990	0.871955	0.174122
8	0.496375	5.504096	0.033333	0.000000	0.023025	0.156508	0.077687	0.949642	0.172534
9	0.454764	5.958860	0.033333	0.000000	0.022024	0.152457	0.069332	1.018974	0.171001
10	0.416642	6.375502	0.033333	0.000000	0.021023	0.148406	0.061832	1.080806	0.169525
11	0.381715	6.757217	0.033333	0.000000	0.020022	0.144355	0.055102	1.135908	0.168103
12	0.349716	7.106932	0.033333	0.000000	0.019020	0.140304	0.049066	1.184975	0.166735
13	0.320399	7.427331	0.033333	0.000000	0.018019	0.136253	0.043655	1.228630	0.165420
14	0.293540	7.720872	0.033333	0.000000	0.017018	0.132202	0.038806	1.267436	0.164157
15	0.268933	7.989805	0.033333	0.000000	0.016017	0.128151	0.034464	1.301900	0.162945
16	0.246388	8.236193	0.033333	0.000000	0.015016	0.124099	0.030577	1.332477	0.161783
17	0.225734	8.461927	0.033333	0.000000	0.014015	0.120048	0.027099	1.359576	0.160670
18	0.206811	8.668737	0.033333	0.000000	0.013014	0.115997	0.023989	1.383565	0.159604
19	0.189474	8.858211	0.033333	0.000000	0.012013	0.111946	0.021211	1.404776	0.158585
20	0.173580	9.031801	0.033333	0.000000	0.011012	0.107895	0.018730	1.423506	0.157610
21	0.159038	9.190839	0.033333	0.000000	0.010011	0.103844	0.016515	1.440021	0.156680
22	0.145706	9.336545	0.033333	0.000000	0.009010	0.099793	0.014540	1.454561	0.155792
23	0.133492	9.470037	0.033333	0.000000	0.008009	0.095742	0.012781	1.467342	0.154946
24	0.122301	9.592338	0.033333	0.000000	0.007008	0.091691	0.011214	1.478556	0.154139
25	0.112049	9.704387	0.033333	0.000000	0.006008	0.087640	0.009820	1.488376	0.153371
26	0.102656	9.807042	0.033333	0.000000	0.005005	0.083589	0.008581	1.496957	0.152641
27	0.094050	9.901092	0.033333	0.000000	0.004004	0.079538	0.007481	1.504437	0.151947
28	0.086166	9.987258	0.033333	0.000000	0.003003	0.075487	0.006504	1.510942	0.151287
29	0.078943	10.066201	0.033333	0.000000	0.002002	0.071436	0.005639	1.516581	0.150661
30	0.072325	10.138526	0.033333	0.000000	0.001001	0.067384	0.004874	1.521454	0.150067
31	0.066262	10.204788	0.000000	-0.012667	0.012667	0.063333	0.004197	1.525651	0.149503
32	0.060707	10.265495	0.000000	-0.012667	0.012046	0.060822	0.003692	1.529343	0.148979
33	0.055618	10.321113	0.000000	-0.012667	0.011425	0.058310	0.003243	1.532586	0.148490
34	0.050956	10.372069	0.000000	-0.012667	0.010805	0.055798	0.002843	1.535430	0.148035
35	0.046684	10.418753	0.000000	-0.012667	0.010184	0.053287	0.002488	1.537917	0.147611
36	0.042771	10.461523	0.000000	-0.012667	0.009563	0.050775	0.002172	1.540089	0.147215
37	0.039185	10.500709	0.000000	-0.012667	0.008943	0.048263	0.001891	1.541980	0.146845
38	0.035900	10.536609	0.000000	-0.012667	0.008322	0.045752	0.001642	1.543623	0.146501
39	0.032891	10.569500	0.000000	-0.012667	0.007701	0.043240	0.001422	1.545045	0.146180
40	0.030134	10.599633	0.000000	-0.012667	0.007081	0.040728	0.001227	1.546272	0.145880

Year f	Fractional Remaining Book Value SB	Return on Equity RE	Return on Debt RD
1	1.000000	0.049000	0.042500
2	0.966667	0.047367	0.041083
3	0.933333	0.045733	0.039667
4	0.900000	0.044100	0.038250
5	0.866667	0.042467	0.036833
6	0.833333	0.040833	0.035417
7	0.800000	0.039200	0.034000
8	0.766667	0.037567	0.032583
9	0.733333	0.035933	0.031167
10	0.700000	0.034300	0.029750
11	0.666667	0.032667	0.028333
12	0.633333	0.031033	0.026917
13	0.600000	0.029400	0.025500
14	0.566667	0.027767	0.024083
15	0.533333	0.026133	0.022667
16	0.500000	0.024500	0.021250
17	0.466667	0.022867	0.019833
18	0.433333	0.021233	0.018417
19	0.400000	0.019600	0.017000
20	0.366667	0.017967	0.015583
21	0.333333	0.016333	0.014167
22	0.300000	0.014700	0.012750
23	0.266667	0.013067	0.011333
24	0.233333	0.011433	0.009917
25	0.200000	0.009800	0.008500
26	0.166667	0.008167	0.007083
27	0.133333	0.006533	0.005667
28	0.100000	0.004900	0.004250
29	0.066667	0.003267	0.002833
30	0.033333	0.001633	0.001417
31	-0.000000	-0.000000	-0.000000
32	-0.020667	-0.001013	-0.000878
33	-0.041333	-0.002025	-0.001757
34	-0.062000	-0.003038	-0.002635
35	-0.082667	-0.004051	-0.003513
36	-0.103333	-0.005063	-0.004392
37	-0.124000	-0.006076	-0.005270
38	-0.144667	-0.007089	-0.006148
39	-0.165333	-0.008101	-0.007027
40	-0.186000	-0.009114	-0.007905

Constant Dollars (Without Inflation)

Year	Present Value Factor pv	Annuity Factor a	Taxes Paid tp	Year-by-Year Carrying Charge CC	Present Value of Carrying Charge	Cumulative Present Value CC Vf,m,n	Levelized CC Pf,m,n
1	0.943656	0.943656	0.020232	0.143274	0.135201	0.135201	0.143274
2	0.890486	1.834141	0.019557	0.140609	0.125210	0.260412	0.141980
3	0.840312	2.674453	0.018883	0.137944	0.115916	0.376328	0.140712
4	0.792965	3.467418	0.018209	0.135280	0.107272	0.483600	0.139470
5	0.748286	4.215704	0.017534	0.132615	0.099234	0.582834	0.138253
6	0.706124	4.921827	0.016860	0.129950	0.091761	0.674595	0.137062
7	0.666338	5.588165	0.016185	0.127286	0.084815	0.759410	0.135896
8	0.628793	6.216958	0.015511	0.124621	0.078361	0.837771	0.134756
9	0.593364	6.810323	0.014837	0.121956	0.072365	0.910136	0.133641
10	0.559931	7.370254	0.014162	0.119292	0.066795	0.976931	0.132551
11	0.528382	7.898636	0.013488	0.116627	0.061624	1.038555	0.131485
12	0.498611	8.397247	0.012813	0.113962	0.056823	1.095377	0.130445
13	0.470517	8.867764	0.012139	0.111298	0.052367	1.147745	0.129429
14	0.444006	9.311770	0.011465	0.108633	0.048234	1.195979	0.128437
15	0.418989	9.730759	0.010790	0.105968	0.044400	1.240378	0.127470
16	0.395381	10.126140	0.010116	0.103304	0.040844	1.281222	0.126526
17	0.373103	10.499243	0.009441	0.100639	0.037549	1.318771	0.125606
18	0.352081	10.851325	0.008767	0.097974	0.034495	1.353266	0.124710
19	0.332243	11.183568	0.008093	0.095310	0.031666	1.384932	0.123836
20	0.313523	11.497091	0.007418	0.092645	0.029046	1.413978	0.122986
21	0.295858	11.792949	0.006744	0.089980	0.026621	1.440600	0.122158
22	0.279188	12.072137	0.006070	0.087315	0.024377	1.464977	0.121352
23	0.263457	12.335594	0.005395	0.084651	0.022302	1.487279	0.120568
24	0.248613	12.584207	0.004721	0.081986	0.020383	1.507662	0.119806
25	0.234605	12.818812	0.004046	0.079321	0.018609	1.526271	0.119065
26	0.221386	13.040198	0.003372	0.076657	0.016971	1.543242	0.118345
27	0.208912	13.249110	0.002698	0.073992	0.015458	1.558699	0.117646
28	0.197141	13.446252	0.002023	0.071327	0.014062	1.572761	0.116967
29	0.186033	13.632285	0.001349	0.068663	0.012774	1.585535	0.116307
30	0.175551	13.807837	0.000674	0.065998	0.011586	1.597121	0.115668
31	0.165660	13.973497	0.012667	0.063333	0.010492	1.607612	0.115047
32	0.156328	14.129823	0.012249	0.061681	0.009642	1.617255	0.114457
33	0.147518	14.277341	0.011830	0.060029	0.008855	1.626110	0.113894
34	0.139206	14.416547	0.011412	0.058377	0.008126	1.634237	0.113358
35	0.131363	14.547910	0.010994	0.056725	0.007452	1.641688	0.112847
36	0.123961	14.671871	0.010576	0.055073	0.006827	1.648515	0.112359
37	0.116977	14.788847	0.010158	0.053421	0.006249	1.654764	0.111893
38	0.110386	14.899233	0.009740	0.051769	0.005715	1.660479	0.111447
39	0.104166	15.003399	0.009322	0.050117	0.005220	1.665699	0.111021
40	0.098297	15.101696	0.008904	0.048464	0.004764	1.670463	0.110614

Year f	Return on Equity RE	Return on Debt RD
1	0.033010	0.026699
2	0.031909	0.025809
3	0.030809	0.024919
4	0.029709	0.024029
5	0.028608	0.023139
6	0.027508	0.022249
7	0.026408	0.021359
8	0.025307	0.020469
9	0.024207	0.019579
10	0.023107	0.018689
11	0.022006	0.017799
12	0.020906	0.016909
13	0.019806	0.016019
14	0.018706	0.015129
15	0.017605	0.014239
16	0.016505	0.013350
17	0.015405	0.012460
18	0.014304	0.011570
19	0.013204	0.010680
20	0.012104	0.009790
21	0.011003	0.008900
22	0.009903	0.008010
23	0.008803	0.007120
24	0.007702	0.006230
25	0.006602	0.005340
26	0.005502	0.004450
27	0.004401	0.003560
28	0.003301	0.002670
29	0.002201	0.001780
30	0.001100	0.000890
31	-0.000000	-0.000000
32	-0.000682	-0.000552
33	-0.001364	-0.001104
34	-0.002047	-0.001655
35	-0.002729	-0.002207
36	-0.003411	-0.002759
37	-0.004093	-0.003311
38	-0.004775	-0.003862
39	-0.005458	-0.004414
40	-0.006140	-0.004966

O&M Cost Levelization Factor Calculations

	Units	Current $	Constant $
Inflation rate	%	3.00	0.00
Discount rate	%	9.15	5.971
Escalation of raw materials above inflation	%	0.00	0.00
Remaining life of power plant	Years	30	30
Apparent escalation rate	%	3.00	0.00
Escalation factor		0.943656	0.943656
Annuity factor		10.138526	13.807837
O&M cost levelization factor		1.361918	1.000000

Exhibit B

250-MW New Plant Combustion Calculation

filename: DOE250.wk4

DOE SCR Project - Economic Evaluation

Name: ECH
Date: 3/22/96 (rev 1), 4/1/96 (rev2), 8/29/96 (rev 3)
Project: DOE SCR Project - Base Case Unit (250 MW) Combustion Calculation

Input Data

Coal Source	Typical High Sulfur	
Heating Value (Btu/lb)	12500	
Plant Heat Rate (BTU/kwh)	9500	
Combustion Air Moisture (#H2O/#Dry Air)	0.013	
Calculated Excess Air (%)	18	
Unit Load (MW)	250	
Flue Gas Temp (F)	700	
Flue Gas Pressure (in. W.G)	-5	14.52 (psia)

Coal Composition	Weight Percent
C	67.48
H	4.51
N	1.43
S	2.33
Cl	0.14
O	5.92
H2O	8.39
ash	9.80
Total	100.00

Field Measured Values	
Measured O2 (% wet)	3.00
Measured SO3 (ppm wet)	0
Measured NOx (ppm wet)	230
Measured Particulate (high) (mg/Nm3)	0
Measured Particulate (low) (mg/Nm3)	0

Combustion Calculation Output Data

Combustion Products	Flue Gas Flow Rate (#mol/h)	Flue Gas Comp (mol%)	Flue Gas Flow Rate (#/h)	Flue Gas Comp (wt%)	Flue Gas Flow Rate (scfm)	Flue Gas Flow Rate (acfm)
CO2	10675.44	14.067	469826	20.775	63875	144286
O2	2284.26	3.010	73096	3.232	13668	30873
N2	56166.33	74.013	1573219	69.566	336062	759125
SO2	138.08	0.1820	8846	0.391	826	1866
SO3	1.38	0.00182	111	0.00489	8	18.66
NO	16.58	0.02185	497	0.02200	99	224.11
NO2	0.87	0.00115	40	0.00178	5	11.80
HCl	4.50	0.00593	164	0.00726	27	60.84
H2O	6600.13	8.697	118934	5.259	39491	89205
ash			16758	0.741		
Total	75,888	100.000	2,261,492	100.000	454,061	1,025,671

Summary	
Calculated O2 (% wet):	3.01
Calculated O2 (% dry):	3.30
Calculated SO3 (ppm wet):	18
Calculated NOx (ppm wet):	230
Calculated NOx (ppm wet corr):	230
Calculated NOx (ppm dry):	252
Calculated NOx (ppm dry corr):	256
Calculated NOx (lb/MBTU):	0.35
Calculated Coal Feed (lb/hr):	190,000
Calculated Heat Input (MBTU/hr):	2,375

Exhibit C

250-MW New Plant - SCR Capital, O&M, and Levelized Costs for 40% Removal

Exhibit C

250 MW Plant - SCR Capital Cost for 40% Removal

Process Areas	**k$**	**$/kw**
Catalyst	$1,856	$7.4
Reactor Housing, Ductwork, Steel	$4,958	$19.8
Sootblowers	$580	$2.3
Ammonia Storage, Handling, and Injection	$1,292	$5.2
ID Fan Differential	$216	$0.9
Air Preheater Differential	$220	$0.9
Ash Handling Differential	$300	$1.2
Electrical	$201	$0.8
Instruments & Controls	$100	$0.4
Testing, Training, Commissioning	$138	$0.6
(A) Total Process Capital (sum of process areas)	$9,861	$39.4
(B) General Facilities (2% of A)	$197	$0.8
(C) Engineering (8% of A)	$789	$3.2
(D) Project Contingency (15% of A+B+C)	$1,627	$6.5
(E) Total Plant Cost (A+B+C+D)	$12,474	$49.9
(F) Allowance for Funds During Construction (1.91% of E)	$238	$1.0
(G) Total Plant Investment (E+F)	$12,712	$50.8
(H) Royalty Allowance (0% of A)	$0	$0.0
(I) Preproduction Cost (2 month startup)	$159	$0.6
(J) Inventory Capital	$103	$0.4
K) Initial Catalyst and Chemical	$0	$0.0
(L) Total Capital Requirements (G+H+I+J+K)	$12,974	$51.9

Exhibit C

250 MW Plant - SCR Operating and Maintenance Cost for 40% Removal

Fixed O&M Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Operating labor	Man-hr	2847	$23.00	$65,000
Maintenance labor				$79,000
Maintenance material				$118,000
Administration/support labor				$43,000
Subtotal Fixed Costs				$305,000
Variable Operating Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Fuels				
Coal	MBTU/hr	3.56	$2.00	$41,000
Sorbent				
n/a				$0
Chemicals/Catalyst				
Ammonia	lb/hr	125	$0.13	$89,000
Catalyst	cu. ft.	(Note 1)	$400	$385,000
Utilities				
Condensate	10^3 lb/hr			$0
Raw water	10^3 gal/hr			$0
Cooling water	10^3 gal/hr			$0
LP steam (0-70 psia)	10^3 lb/hr			$0
MP steam (70-250 psia)	10^3 lb/hr			$0
HP steam (>250 psia)	10^3 lb/hr			$0
Electric power	kWh/hr	622	$0.03	$106,000
Byproduct Credits				
n/a				$0
Waste Disposal Charges				
n/a				$0
Subtotal Variable Cost				$621,000
TOTAL O&M COSTS (FIXED + VARIABLE)				$926,000

Note 1 - Catalyst is not replaced on a yearly basis. Refer to catalyst management plan for addition and/or replacement schedule. Dollar amount shown in this table represents a levelized annual reserve for replacement based on present worth analysis of the catalyst replacement schedule.

Exhibit C

250 MW Plant - Summary of Performance and Cost Data for 40% Removal

Power Plant Attributes	**Units**	**Value**
Plant capacity, (net)	MWe	235
Power produced, (net)	10^6 kWh/yr	1338.09
Capacity factor	%	65
Plant life	years	30
Coal feed	tons/yr	540,930
Sulfur in coal	wt %	2.33
Emission Control Data	**Units**	**Value**
SCR removal efficiency	%	40
Emission without controls	lb/MBTU	0.35
Emission with controls	lb/MBTU	0.21
Amount removed	ton/yr	916

	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.454	0.116	1.125
Fixed O&M Cost	1.362	0.311	1.000	0.228
Variable O&M Cost	1.362	0.632	1.000	0.384
Total Cost		2.397		1.737
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$2,124	0.116	$1,642
Fixed O&M Cost	1.362	$454	1.000	$333
Variable O&M Cost	1.362	$924	1.000	$561
Total Cost		$3,502		$2,536

Exhibit D

250-MW New Plant - SCR Capital, O&M, and Levelized Costs for 60% Removal (Base Case)

Exhibit D

250 MW Base Case SCR Capital Cost for 60% Removal

Process Areas	**k$**	**$/kw**
Catalyst	$2,168	$8.7
Reactor Housing, Ductwork, Steel	$4,958	$19.8
Sootblowers	$580	$2.3
Ammonia Storage, Handling, and Injection	$1,292	$5.2
ID Fan Differential	$216	$0.9
Air Preheater Differential	$220	$0.9
Ash Handling Differential	$300	$1.2
Electrical	$201	$0.8
Instruments & Controls	$100	$0.4
Testing, Training, Commissioning	$138	$0.6
(A) Total Process Capital (sum of process areas)	$10,172	$40.7
(B) General Facilities (2% of A)	$203	$0.8
(C) Engineering (8% of A)	$814	$3.3
(D) Project Contingency (15% of A+B+C)	$1,678	$6.7
(E) Total Plant Cost (A+B+C+D)	$12,868	$51.5
(F) Allowance for Funds During Construction (1.91% of E)	$246	$1.0
(G) Total Plant Investment (E+F)	$13,114	$52.5
(H) Royalty Allowance (0% of A)	$0	$0.0
(I) Preproduction Cost (2 month startup)	$179	$0.7
(J) Inventory Capital	$122	$0.5
K) Initial Catalyst and Chemical	$0	$0.0
(L) Total Capital Requirements (G+H+I+J+K)	$13,415	$53.7

Exhibit D

250 MW Base Case SCR Operating and Maintenance Cost for 60% Removal

Fixed O&M Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Operating labor	Man-hr	2847	$23.00	$65,000
Maintenance labor				$81,000
Maintenance material				$122,000
Administration/support labor				$44,000
Subtotal Fixed Costs				$312,000
Variable Operating Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Fuels				
Coal	MBTU/hr	3.56	$2.00	$41,000
Sorbent				
n/a				$0
Chemicals/Catalyst				
Ammonia	lb/hr	187	$0.13	$133,000
Catalyst	cu. ft.	(Note 1)	$400	$450,000
Utilities				
Condensate	10^3 lb/hr			$0
Raw water	10^3 gal/hr			$0
Cooling water	10^3 gal/hr			$0
LP steam (0-70 psia)	10^3 lb/hr			$0
MP steam (70-250 psia)	10^3 lb/hr			$0
HP steam (>250 psia)	10^3 lb/hr			$0
Electric power	kWh/hr	639	$0.03	$109,000
Byproduct Credits				
n/a				$0
Waste Disposal Charges				
n/a				$0
Subtotal Variable Cost				$733,000
TOTAL O&M COSTS (FIXED + VARIABLE)				$1,045,000

Note 1 - Catalyst is not replaced on a yearly basis. Refer to catalyst management plan for addition and/or replacement schedule. Dollar amount shown in this table represents a levelized annual reserve for replacement based on present worth analysis of the catalyst replacement schedule.

Exhibit D

250 MW Base Case Summary of Performance and Cost Data for 60% Removal

Power Plant Attributes		**Units**		**Value**
Plant capacity, (net)		MWe		235
Power produced, (net)		10^6 kWh/yr		1338.09
Capacity factor		%		65
Plant life		years		30
Coal feed		tons/yr		540,930
Sulfur in coal		wt %		2.33
Emission Control Data		**Units**		**Value**
SCR removal efficiency		%		60
Emission without controls		lb/MBTU		0.35
Emission with controls		lb/MBTU		0.14
Amount removed		ton/yr		1374
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.746	1.000	0.454
Total Cost		2.569		1.851
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,464	0.116	$1,132
Fixed O&M Cost	1.362	$310	1.000	$228
Variable O&M Cost	1.362	$726	1.000	$442
Total Cost		$2,500		$1,802

Exhibit E

250-MW New Plant - SCR Capital, O&M, and Levelized Costs for 80% Removal

Exhibit E

250 MW Plant - SCR Capital Cost for 80% Removal

Process Areas	k$	$/kw
Catalyst	$2,536	$10.1
Reactor Housing, Ductwork, Steel	$4,958	$19.8
Sootblowers	$580	$2.3
Ammonia Storage, Handling, and Injection	$1,454	$5.8
ID Fan Differential	$216	$0.9
Air Preheater Differential	$220	$0.9
Ash Handling Differential	$300	$1.2
Electrical	$201	$0.8
Instruments & Controls	$100	$0.4
Testing, Training, Commissioning	$138	$0.6
(A) Total Process Capital (sum of process areas)	$10,702	$42.8
(B) General Facilities (2% of A)	$214	$0.9
(C) Engineering (8% of A)	$856	$3.4
(D) Project Contingency (15% of A+B+C)	$1,766	$7.1
(E) Total Plant Cost (A+B+C+D)	$13,538	$54.2
(F) Allowance for Funds During Construction (1.91% of E)	$259	$1.0
(G) Total Plant Investment (E+F)	$13,797	$55.2
(H) Royalty Allowance (0% of A)	$0	$0.0
(I) Preproduction Cost (2 month startup)	$202	$0.8
(J) Inventory Capital	$143	$0.6
K) Initial Catalyst and Chemical	$0	$0.0
(L) Total Capital Requirements (G+H+I+J+K)	$14,142	$56.6

Exhibit E

250 MW Plant - SCR Operating and Maintenance Cost for 80% Removal

Fixed O&M Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Operating labor	Man-hr	2847	$23.00	$65,000
Maintenance labor				$86,000
Maintenance material				$128,000
Administration/support labor				$45,000
Subtotal Fixed Costs				$324,000
Variable Operating Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Fuels				
Coal	MBTU/hr	3.56	$2.00	$41,000
Sorbent				
n/a				$0
Chemicals/Catalyst				
Ammonia	lb/hr	250	$0.13	$178,000
Catalyst	cu. ft.	(Note 1)	$400	$526,000
Utilities				
Condensate	10^3 lb/hr			$0
Raw water	10^3 gal/hr			$0
Cooling water	10^3 gal/hr			$0
LP steam (0-70 psia)	10^3 lb/hr			$0
MP steam (70-250 psia)	10^3 lb/hr			$0
HP steam (>250 psia)	10^3 lb/hr			$0
Electric power	kWh/hr	655	$0.03	$112,000
Byproduct Credits				
n/a				$0
Waste Disposal Charges				
n/a				$0
Subtotal Variable Cost				$857,000
TOTAL O&M COSTS (FIXED + VARIABLE)				$1,181,000

Note 1 - Catalyst is not replaced on a yearly basis. Refer to catalyst management plan for addition and/or replacement schedule. Dollar amount shown in this table represents a levelized annual reserve for replacement based on present worth analysis of the catalyst replacement schedule.

Exhibit E

250 MW Plant - Summary of Performance and Cost Data for 80% Removal

Power Plant Attributes			Units	Value
Plant capacity, (net)			MWe	235
Power produced, (net)			10^6 kWh/yr	1338.09
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	540,930
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	80
Emission without controls			lb/MBTU	0.35
Emission with controls			lb/MBTU	0.07
Amount removed			ton/yr	1833
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.585	0.116	1.226
Fixed O&M Cost	1.362	0.331	1.000	0.243
Variable O&M Cost	1.362	0.872	1.000	0.531
Total Cost		2.788		2.000
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,158	0.116	$895
Fixed O&M Cost	1.362	$241	1.000	$177
Variable O&M Cost	1.362	$637	1.000	$388
Total Cost		$2,036		$1,460

Exhibit F

125-MW New Plant - Combustion Calculation

filename: DOE125 wk4

DOE SCR Project - Economic Evaluation

Name: ECH
Date: 3/22/96 (rev 1), 4/1/96 (rev2), 8/29/96 (rev 3)
Project: DOE SCR Project - 125 MW Plant Combustion Calculation

Input Data

Coal Source	Typical High Sulfur	
Heating Value (Btu/lb)	12500	
Plant Heat Rate (BTU/kwh)	9500	
Combustion Air Moisture (#H2O/#Dry Air)	0.013	
Calculated Excess Air (%)	18	
Unit Load (MW)	125	
Flue Gas Temp (F)	700	
Flue Gas Pressure (in. W.G)	-5	14.52 (psia)

Coal Composition	Weight Percent
C	67.48
H	4.51
N	1.43
S	2.33
Cl	0.14
O	5.92
H2O	8.39
ash	9.80
Total	100.00

Field Measured Values	
Measured O2 (% wet)	3.00
Measured SO3 (ppm wet)	0
Measured NOx (ppm wet)	230
Measured Particulate (high) (mg/Nm3)	0
Measured Particulate (low) (mg/Nm3)	0

Combustion Calculation Output Data

Combustion Products	Flue Gas Flow Rate (#mol/h)	Flue Gas Comp (mol%)	Flue Gas Flow Rate (#/h)	Flue Gas Comp (wt%)	Flue Gas Flow Rate (scfm)	Flue Gas Flow Rate (acfm)
CO2	5337.72	14.067	234913	20.775	31937	72143
O2	1142.13	3.010	36548	3.232	6834	15437
N2	28083.17	74.013	786609	69.566	168031	379563
SO2	69.04	0.1820	4423	0.391	413	933
SO3	0.69	0.00182	55	0.00489	4	9.33
NO	8.29	0.02185	249	0.02200	50	112.05
NO2	0.44	0.00115	20	0.00178	3	5.90
HCl	2.25	0.00593	82	0.00726	13	30.42
H2O	3300.07	8.697	59467	5.259	19745	44603
ash			8379	0.741		
Total	37,944	100.000	1,130,746	100.000	227,030	512,835

Summary	
Calculated O2 (% wet):	3.01
Calculated O2 (% dry):	3.30
Calculated SO3 (ppm wet):	18
Calculated NOx (ppm wet):	230
Calculated NOx (ppm wet corr):	230
Calculated NOx (ppm dry):	252
Calculated NOx (ppm dry corr):	256
Calculated NOx (lb/MBTU):	0.35
Calculated Coal Feed (lb/hr):	95,000
Calculated Heat Input (MBTU/hr):	1,188

Exhibit G

125-MW New Plant - SCR Capital, O&M, and Levelized Costs for 60% Removal

Exhibit G

125 MW Plant - SCR Capital Cost for 60% Removal

Process Areas	**k$**	**$/kw**
Catalyst	$1,230	$9.8
Reactor Housing, Ductwork, Steel	$2,814	$22.5
Sootblowers	$329	$2.6
Ammonia Storage, Handling, and Injection	$733	$5.9
ID Fan Differential	$123	$1.0
Air Preheater Differential	$125	$1.0
Ash Handling Differential	$170	$1.4
Electrical	$114	$0.9
Instruments & Controls	$57	$0.5
Testing, Training, Commissioning	$78	$0.6
(A) Total Process Capital (sum of process areas)	$5,773	$46.2
(B) General Facilities (2% of A)	$115	$0.9
(C) Engineering (8% of A)	$462	$3.7
(D) Project Contingency (15% of A+B+C)	$952	$7.6
(E) Total Plant Cost (A+B+C+D)	$7,302	$58.4
(F) Allowance for Funds During Construction (1.91% of E)	$139	$1.1
(G) Total Plant Investment (E+F)	$7,442	$59.5
(H) Royalty Allowance (0% of A)	$0	$0.0
(I) Preproduction Cost (2 month startup)	$99	$0.8
(J) Inventory Capital	$61	$0.5
K) Initial Catalyst and Chemical	$0	$0.0
(L) Total Capital Requirements (G+H+I+J+K)	$7,602	$60.8

Exhibit G

125 MW Plant - SCR Operating and Maintenance Cost for 60% Removal

Fixed O&M Costs	Units	Quantity	$/Unit	$/ yr
Operating labor	Man-hr	2847	$23.00	$65,000
Maintenance labor				$46,000
Maintenance material				$69,000
Administration/support labor				$33,000
Subtotal Fixed Costs				$213,000
Variable Operating Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Fuels				
Coal	MBTU/hr	1.78	$2.00	$20,000
Sorbent				
n/a				$0
Chemicals/Catalyst				
Ammonia	lb/hr	94	$0.13	$67,000
Catalyst	cu. ft.	(Note 1)	$400	$225,000
Utilities				
Condensate	10^3 lb/hr			$0
Raw water	10^3 gal/hr			$0
Cooling water	10^3 gal/hr			$0
LP steam (0-70 psia)	10^3 lb/hr			$0
MP steam (70-250 psia)	10^3 lb/hr			$0
HP steam (>250 psia)	10^3 lb/hr			$0
Electric power	kWh/hr	319	$0.03	$55,000
Byproduct Credits				
n/a				$0
Waste Disposal Charges				
n/a				$0
Subtotal Variable Cost				$367,000
TOTAL O&M COSTS (FIXED + VARIABLE)				$580,000

Note 1 - Catalyst is not replaced on a yearly basis. Refer to catalyst management plan for addition and/or replacement schedule. Dollar amount shown in this table represents a levelized annual reserve for replacement based on present worth analysis of the catalyst replacement schedule.

Exhibit G

125 MW Plant - Summary of Performance and Cost Data for 60% Removal

Power Plant Attributes			**Units**	**Value**
Plant capacity, (net)			MWe	117.5
Power produced, (net)			10^6 kWh/yr	669.045
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	270,465
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.35
Emission with controls			lb/MBTU	0.14
Amount removed			ton/yr	687
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.704	0.116	1.318
Fixed O&M Cost	1.362	0.437	1.000	0.321
Variable O&M Cost	1.362	0.747	1.000	0.454
Total Cost		2.888		2.093
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,659	0.116	$1,283
Fixed O&M Cost	1.362	$425	1.000	$312
Variable O&M Cost	1.362	$727	1.000	$442
Total Cost		$2,811		$2,037

Exhibit H

700-MW New Plant - Combustion Calculation

filename: DOE700.wk4

DOE SCR Project - Economic Evaluation

Name: ECH
Date: 3/22/96 (rev 1), 4/1/96 (rev2), 8/29/96 (rev 3)
Project: DOE SCR Project - 700 MW Plant Combustion Calculation

Input Data

Coal Source	Typical High Sulfur		Coal Composition	Weight Percent
Heating Value (Btu/lb)	12500		C	67.48
			H	4.51
Plant Heat Rate (BTU/kwh)	9500		N	1.43
			S	2.33
Combustion Air Moisture (#H2O/#Dry Air)	0.013		Cl	0.14
			O	5.92
Calculated Excess Air (%)	18		H2O	8.39
			ash	9.80
Unit Load (MW)	700			
			Total	100.00
Flue Gas Temp (F)	700			
Flue Gas Pressure (in. W.G)	-5	14.52	(psia)	

Field Measured Values	
Measured O2 (% wet)	3.00
Measured SO3 (ppm wet)	0
Measured NOx (ppm wet)	230
Measured Particulate (high) (mg/Nm3)	0
Measured Particulate (low) (mg/Nm3)	0

Combustion Calculation Output Data

Combustion Products	Flue Gas Flow Rate (#mol/h)	Flue Gas Comp (mol%)	Flue Gas Flow Rate (#/h)	Flue Gas Comp (wt%)	Flue Gas Flow Rate (scfm)	Flue Gas Flow Rate (acfm)
CO2	29891.22	14.067	1315513	20.775	178849	404000
O2	6395.94	3.010	204670	3.232	38269	86445
N2	157265.72	74.013	4405013	69.566	940973	2125550
SO2	386.64	0.1820	24768	0.391	2313	5226
SO3	3.87	0.00182	310	0.00489	23	52.26
NO	46.43	0.02185	1393	0.02200	278	627.51
NO2	2.44	0.00115	112	0.00178	15	33.03
HCl	12.60	0.00593	460	0.00726	75	170.35
H2O	18480.37	8.697	333016	5.259	110574	249774
ash			46922	0.741		
Total	212,485	100.000	6,332,177	100.000	1,271,370	2,871,878

Summary	
Calculated O2 (% wet):	3.01
Calculated O2 (% dry):	3.30
Calculated SO3 (ppm wet):	18
Calculated NOx (ppm wet):	230
Calculated NOx (ppm wet corr):	230
Calculated NOx (ppm dry):	252
Calculated NOx (ppm dry corr):	256
Calculated NOx (lb/MBTU):	0.35
Calculated Coal Feed (lb/hr):	532,000
Calculated Heat Input (MBTU/hr):	6,650

Exhibit I

700-MW New Plant - SCR Capital, O&M, and Levelized Costs for 60% Removal

Exhibit I

700 MW Plant - SCR Capital Cost for 60% Removal

Process Areas	**k$**	**$/kw**
Catalyst	$6,078	$8.7
Reactor Housing, Ductwork, Steel	$12,554	$17.9
Sootblowers	$1,202	$1.7
Ammonia Storage, Handling, and Injection	$1,549	$2.2
ID Fan Differential	$512	$0.7
Air Preheater Differential	$524	$0.7
Ash Handling Differential	$617	$0.9
Electrical	$319	$0.5
Instruments & Controls	$150	$0.2
Testing, Training, Commissioning	$175	$0.3
(A) Total Process Capital (sum of process areas)	$23,681	$33.8
(B) General Facilities (2% of A)	$474	$0.7
(C) Engineering (8% of A)	$1,894	$2.7
(D) Project Contingency (15% of A+B+C)	$3,907	$5.6
(E) Total Plant Cost (A+B+C+D)	$29,956	$42.8
(F) Allowance for Funds During Construction (1.91% of E)	$572	$0.8
(G) Total Plant Investment (E+F)	$30,528	$43.6
(H) Royalty Allowance (0% of A)	$0	$0.0
(I) Preproduction Cost (2 month startup)	$457	$0.7
(J) Inventory Capital	$342	$0.5
K) Initial Catalyst and Chemical	$0	$0.0
(L) Total Capital Requirements (G+H+I+J+K)	$31,327	$44.8

Exhibit I

700 MW Plant - SCR Operating and Maintenance Cost for 60% Removal

Fixed O&M Costs	Units	Quantity	$/Unit	$/ yr
Operating labor	Man-hr	2847	$23.00	$65,000
Maintenance labor				$189,000
Maintenance material				$284,000
Administration/support labor				$76,000
Subtotal Fixed Costs				$614,000
Variable Operating Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Fuels				
Coal	MBTU/hr	9.98	$2.00	$114,000
Sorbent				
n/a				$0
Chemicals/Catalyst				
Ammonia	lb/hr	525	$0.13	$373,000
Catalyst	cu. ft.	(Note 1)	$400	$1,260,000
Utilities				
Condensate	10^3 lb/hr			$0
Raw water	10^3 gal/hr			$0
Cooling water	10^3 gal/hr			$0
LP steam (0-70 psia)	10^3 lb/hr			$0
MP steam (70-250 psia)	10^3 lb/hr			$0
HP steam (>250 psia)	10^3 lb/hr			$0
Electric power	kWh/hr	1788	$0.03	$306,000
Byproduct Credits				
n/a				$0
Waste Disposal Charges				
n/a				$0
Subtotal Variable Cost				$2,053,000
TOTAL O&M COSTS (FIXED + VARIABLE)				$2,667,000

Note 1 - Catalyst is not replaced on a yearly basis. Refer to catalyst management plan for addition and/or replacement schedule. Dollar amount shown in this table represents a levelized annual reserve for replacement based on present worth analysis of the catalyst replacement schedule.

Exhibit I

700 MW Plant - Summary of Performance and Cost Data for 60% Removal

Power Plant Attributes			**Units**	**Value**
Plant capacity, (net)			MWe	658
Power produced, (net)			10^6 kWh/yr	3746.652
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	1,514,604
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.35
Emission with controls			lb/MBTU	0.14
Amount removed			ton/yr	3848
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.254	0.116	0.970
Fixed O&M Cost	1.360	0.223	1.000	0.164
Variable O&M Cost	1.360	0.745	1.000	0.455
Total Cost		2.222		1.589
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,221	0.116	$944
Fixed O&M Cost	1.360	$218	1.000	$160
Variable O&M Cost	1.360	$726	1.000	$443
Total Cost		$2,165		$1,547

Exhibit J

250-MW New Plant
Summary of Performance and Levelized Cost Vs. Inlet NO_X Concentration

Exhibit J

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 0.45 lb/MBTU Inlet NOx Concentration

Power Plant Attributes	Units	Value
Plant capacity, (net)	MWe	235
Power produced, (net)	10^6 kWh/yr	1338.09
Capacity factor	%	65
Plant life	years	30
Coal feed	tons/yr	540,930
Sulfur in coal	wt %	2.33
Emission Control Data	**Units**	**Value**
SCR removal efficiency	%	60
Emission without controls	lb/MBTU	0.45
Emission with controls	lb/MBTU	0.18
Amount removed	ton/yr	1767

	Current Dollars		Constant Dollars	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.788	1.000	0.485
Total Cost		2.611		1.882
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,139	0.116	$881
Fixed O&M Cost	1.362	$241	1.000	$177
Variable O&M Cost	1.362	$597	1.000	$367
Total Cost		$1,977		$1,425

Exhibit J

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 0.40 lb/MBTU Inlet NOx Concentration

Power Plant Attributes	**Units**	**Value**
Plant capacity, (net)	MWe	235
Power produced, (net)	10^6 kWh/yr	1338.09
Capacity factor	%	65
Plant life	years	30
Coal feed	tons/yr	540,930
Sulfur in coal	wt %	2.33
Emission Control Data	**Units**	**Value**
SCR removal efficiency	%	60
Emission without controls	lb/MBTU	0.40
Emission with controls	lb/MBTU	0.16
Amount removed	ton/yr	1571

	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.767	1.000	0.469
Total Cost		2.590		1.866
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,281	0.116	$991
Fixed O&M Cost	1.362	$271	1.000	$199
Variable O&M Cost	1.362	$653	1.000	$400
Total Cost		$2,205		$1,590

Exhibit J

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 0.35 lb/MBTU Inlet NOx Concentration

Power Plant Attributes	**Units**	**Value**
Plant capacity, (net)	MWe	235
Power produced, (net)	10^6 kWh/yr	1338.09
Capacity factor	%	65
Plant life	years	30
Coal feed	tons/yr	540,930
Sulfur in coal	wt %	2.33
Emission Control Data	**Units**	**Value**
SCR removal efficiency	%	60
Emission without controls	lb/MBTU	0.35
Emission with controls	lb/MBTU	0.14
Amount removed	ton/yr	1374

	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.746	1.000	0.454
Total Cost		2.569		1.851
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,464	0.116	$1,132
Fixed O&M Cost	1.362	$310	1.000	$228
Variable O&M Cost	1.362	$726	1.000	$442
Total Cost		$2,500		$1,802

Exhibit J

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 0.30 lb/MBTU Inlet NOx Concentration

Power Plant Attributes			**Units**	**Value**
Plant capacity, (net)			MWe	235
Power produced, (net)			10^6 kWh/yr	1338.09
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	540,930
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.30
Emission with controls			lb/MBTU	0.12
Amount removed			ton/yr	1178
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.726	1.000	0.439
Total Cost		2.549		1.836
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,708	0.116	$1,321
Fixed O&M Cost	1.362	$362	1.000	$266
Variable O&M Cost	1.362	$824	1.000	$499
Total Cost		$2,894		$2,086

Exhibit J

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 0.25 lb/MBTU Inlet NOx Concentration

Power Plant Attributes			**Units**	**Value**
Plant capacity, (net)			MWe	235
Power produced, (net)			10^6 kWh/yr	1338.09
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	540,930
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.25
Emission with controls			lb/MBTU	0.10
Amount removed			ton/yr	982
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.706	1.000	0.424
Total Cost		2.529		1.821
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$2,050	0.116	$1,585
Fixed O&M Cost	1.362	$434	1.000	$319
Variable O&M Cost	1.362	$962	1.000	$579
Total Cost		$3,446		$2,483

Exhibit K

250-MW New Plant
Summary of Performance and Levelized Cost Vs. Catalyst Relative Activity
(Catalyst Management Plan)

Exhibit K

Catalyst Management Plan Sensitivity (K/Ko = 0.70)
250 MW Plant - SCR Operating and Maintenance Cost for 60% Removal

Power Plant Attributes			**Units**	**Value**
Plant capacity, (net)			MWe	235
Power produced, (net)			10^6 kWh/yr	1338.09
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	540,930
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.35
Emission with controls			lb/MBTU	0.14
Amount removed			ton/yr	1374
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.891	1.000	0.535
Total Cost		2.714		1.932
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,464	0.116	$1,132
Fixed O&M Cost	1.362	$310	1.000	$228
Variable O&M Cost	1.362	$868	1.000	$521
Total Cost		$2,642		$1,881

Exhibit K

Catalyst Management Plan Sensitivity (K/Ko = 0.80)
250 MW Plant - SCR Operating and Maintenance Cost for 60% Removal

Power Plant Attributes	Units	Value
Plant capacity, (net)	MWe	235
Power produced, (net)	10^6 kWh/yr	1338.09
Capacity factor	%	65
Plant life	years	30
Coal feed	tons/yr	540,930
Sulfur in coal	wt %	2.33
Emission Control Data	**Units**	**Value**
SCR removal efficiency	%	60
Emission without controls	lb/MBTU	0.35
Emission with controls	lb/MBTU	0.14
Amount removed	ton/yr	1374

	Current Dollars		Constant Dollars	
Levelized Cost, mills/kWhr	Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.746	1.000	0.454
Total Cost		2.569		1.851
Levelized Cost, $/ton NOx Removed	Factor	$/ton	Factor	$/ton
Capital Charge	0.150	$1,464	0.116	$1,132
Fixed O&M Cost	1.362	$310	1.000	$228
Variable O&M Cost	1.362	$726	1.000	$442
Total Cost		$2,500		$1,802

Exhibit K

Catalyst Management Plan Sensitivity (K/Ko = 0.90)
250 MW Plant - SCR Operating and Maintenance Cost for 60% Removal

Power Plant Attributes	**Units**	**Value**
Plant capacity, (net)	MWe	235
Power produced, (net)	10^6 kWh/yr	1338.09
Capacity factor	%	65
Plant life	years	30
Coal feed	tons/yr	540,930
Sulfur in coal	wt %	2.33
Emission Control Data	**Units**	**Value**
SCR removal efficiency	%	60
Emission without controls	lb/MBTU	0.35
Emission with controls	lb/MBTU	0.14
Amount removed	ton/yr	1374

	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.508	1.000	0.319
Total Cost		2.331		1.716
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,464	0.116	$1,132
Fixed O&M Cost	1.362	$310	1.000	$228
Variable O&M Cost	1.362	$495	1.000	$311
Total Cost		$2,269		$1,671

Exhibit L

250-MW New Plant
Summary of Performance and Levelized Cost Vs. Return on Common Equity

Exhibit L

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 7.0% Return on Common Equity

Power Plant Attributes			**Units**	**Value**
Plant capacity, (net)			MWe	235
Power produced, (net)			10^6 kWh/yr	1338.09
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	540,930
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.35
Emission with controls			lb/MBTU	0.14
Amount removed			ton/yr	1374
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.132	1.323	0.100	1.003
Fixed O&M Cost	1.395	0.326	1.000	0.234
Variable O&M Cost	1.395	0.708	1.000	0.454
Total Cost		2.357		1.691
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.132	$1,288	0.100	$976
Fixed O&M Cost	1.395	$318	1.000	$228
Variable O&M Cost	1.395	$689	1.000	$442
Total Cost		$2,295		$1,646

Exhibit L

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 9.0% Return on Common Equity

Power Plant Attributes			**Units**	**Value**
Plant capacity, (net)			MWe	235
Power produced, (net)			10^6 kWh/yr	1338.09
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	540,930
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.35
Emission with controls			lb/MBTU	0.14
Amount removed			ton/yr	1374
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.141	1.414	0.108	1.083
Fixed O&M Cost	1.378	0.322	1.000	0.234
Variable O&M Cost	1.378	0.727	1.000	0.454
Total Cost		2.463		1.771
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.141	$1,376	0.108	$1,054
Fixed O&M Cost	1.378	$314	1.000	$228
Variable O&M Cost	1.378	$708	1.000	$442
Total Cost		$2,398		$1,724

Exhibit L

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 11.0% Return on Common Equity

Power Plant Attributes		**Units**		**Value**
Plant capacity, (net)		MWe		235
Power produced, (net)		10^6 kWh/yr		1338.09
Capacity factor		%		65
Plant life		years		30
Coal feed		tons/yr		540,930
Sulfur in coal		wt %		2.33
Emission Control Data		**Units**		**Value**
SCR removal efficiency		%		60
Emission without controls		lb/MBTU		0.35
Emission with controls		lb/MBTU		0.14
Amount removed		ton/yr		1374
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.504	0.116	1.163
Fixed O&M Cost	1.362	0.319	1.000	0.234
Variable O&M Cost	1.362	0.746	1.000	0.454
Total Cost		2.569		1.851
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,464	0.116	$1,132
Fixed O&M Cost	1.362	$310	1.000	$228
Variable O&M Cost	1.362	$726	1.000	$442
Total Cost		$2,500		$1,802

Exhibit L

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 13.0% Return on Common Equity

Power Plant Attributes	Units	Value
Plant capacity, (net)	MWe	235
Power produced, (net)	10^6 kWh/yr	1338.09
Capacity factor	%	65
Plant life	years	30
Coal feed	tons/yr	540,930
Sulfur in coal	wt %	2.33

Emission Control Data	Units	Value
SCR removal efficiency	%	60
Emission without controls	lb/MBTU	0.35
Emission with controls	lb/MBTU	0.14
Amount removed	ton/yr	1374

	Current Dollars		Constant Dollars	
Levelized Cost, mills/kWhr	Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge	0.160	1.604	0.124	1.243
Fixed O&M Cost	1.347	0.315	1.000	0.234
Variable O&M Cost	1.347	0.766	1.000	0.454
Total Cost		2.685		1.931
Levelized Cost, $/ton NOx Removed	Factor	$/ton	Factor	$/ton
Capital Charge	0.160	$1,562	0.124	$1,210
Fixed O&M Cost	1.347	$307	1.000	$228
Variable O&M Cost	1.347	$746	1.000	$442
Total Cost		$2,615		$1,880

Exhibit L

250 MW Plant - 60% NOx Reduction
Summary of Performance and Cost Data
For 15.0% Return on Common Equity

Power Plant Attributes			**Units**	**Value**
Plant capacity, (net)			MWe	235
Power produced, (net)			10^6 kWh/yr	1338.09
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	540,930
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.35
Emission with controls			lb/MBTU	0.14
Amount removed			ton/yr	1374
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.169	1.694	0.133	1.333
Fixed O&M Cost	1.333	0.312	1.000	0.234
Variable O&M Cost	1.333	0.786	1.000	0.454
Total Cost		2.792		2.021
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.169	$1,650	0.133	$1,298
Fixed O&M Cost	1.333	$304	1.000	$228
Variable O&M Cost	1.333	$766	1.000	$442
Total Cost		$2,720		$1,968

Exhibit M

250-MW New Plant
Summary of Capital, O&M, and Levelized Cost Vs. Catalyst Price

Exhibit M

Catalyst Price Sensitivity ($350/ft3)
250 MW Base Case SCR Capital Cost for 60% Removal

Process Areas	**k$**	**$/kw**
Catalyst (@ $350/ft3)	$1,897	$7.6
Reactor Housing, Ductwork, Steel	$4,958	$19.8
Sootblowers	$580	$2.3
Ammonia Storage, Handling, and Injection	$1,292	$5.2
ID Fan Differential	$216	$0.9
Air Preheater Differential	$220	$0.9
Ash Handling Differential	$300	$1.2
Electrical	$201	$0.8
Instruments & Controls	$100	$0.4
Testing, Training, Commissioning	$138	$0.6
(A) Total Process Capital (sum of process areas)	$9,901	$39.6
(B) General Facilities (2% of A)	$198	$0.8
(C) Engineering (8% of A)	$792	$3.2
(D) Project Contingency (15% of A+B+C)	$1,634	$6.5
(E) Total Plant Cost (A+B+C+D)	$12,525	$50.1
(F) Allowance for Funds During Construction (1.91% of E)	$239	$1.0
(G) Total Plant Investment (E+F)	$12,764	$51.1
(H) Royalty Allowance (0% of A)	$0	$0.0
(I) Preproduction Cost (2 month startup)	$165	$0.7
(J) Inventory Capital	$111	$0.4
K) Initial Catalyst and Chemical	$0	$0.0
(L) Total Capital Requirements (G+H+I+J+K)	$13,040	$52.2

Exhibit M

Catalyst Price Sensitivity (@ $350/ft3)
250 MW Base Case SCR Operating and Maintenance Cost for 60% Removal

Fixed O&M Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Operating labor	Man-hr	2847	$23.00	$65,000
Maintenance labor				$79,000
Maintenance material				$119,000
Administration/support labor				$43,000
Subtotal Fixed Costs				$306,000
Variable Operating Costs	**Units**	**Quantity**	**$/Unit**	**$/ yr**
Fuels				
Coal	MBTU/hr	3.56	$2.00	$41,000
Sorbent				
n/a				$0
Chemicals/Catalyst				
Ammonia	lb/hr	187	$0.13	$133,000
Catalyst	cu. ft.	(Note 1)	**$350**	$394,000
Utilities				
Condensate	10^3 lb/hr			$0
Raw water	10^3 gal/hr			$0
Cooling water	10^3 gal/hr			$0
LP steam (0-70 psia)	10^3 lb/hr			$0
MP steam (70-250 psia)	10^3 lb/hr			$0
HP steam (>250 psia)	10^3 lb/hr			$0
Electric power	kWh/hr	639	$0.03	$109,000
Byproduct Credits				
n/a				$0
Waste Disposal Charges				
n/a				$0
Subtotal Variable Cost				$677,000
TOTAL O&M COSTS (FIXED + VARIABLE)				$983,000

Note 1 - Catalyst is not replaced on a yearly basis. Refer to catalyst management plan for addition and/or replacement schedule. Dollar amount shown in this table represents a levelized annual reserve for replacement based on present worth analysis of the catalyst replacement schedule.

Exhibit M

Catalyst Price Sensitivity (@ $350/ft3)
250 MW Base Case SCR Operating and Maintenance Cost for 60% Removal

Power Plant Attributes			Units	Value
Plant capacity, (net)			MWe	235
Power produced, (net)			10^6 kWh/yr	1338.09
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	540,930
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.35
Emission with controls			lb/MBTU	0.14
Amount removed			ton/yr	1374
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.462	0.116	1.130
Fixed O&M Cost	1.362	0.312	1.000	0.229
Variable O&M Cost	1.362	0.689	1.000	0.424
Total Cost		2.463		1.783
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,423	0.116	$1,101
Fixed O&M Cost	1.362	$304	1.000	$223
Variable O&M Cost	1.362	$671	1.000	$413
Total Cost		$2,398		$1,737

Exhibit M

Catalyst Price Sensitivity ($450/ft3)
250 MW Base Case SCR Capital Cost for 60% Removal

Process Areas	k$	$/kw
Catalyst (@ $450/ft3)	$2,438	$9.8
Reactor Housing, Ductwork, Steel	$4,958	$19.8
Sootblowers	$580	$2.3
Ammonia Storage, Handling, and Injection	$1,292	$5.2
ID Fan Differential	$216	$0.9
Air Preheater Differential	$220	$0.9
Ash Handling Differential	$300	$1.2
Electrical	$201	$0.8
Instruments & Controls	$100	$0.4
Testing, Training, Commissioning	$138	$0.6
(A) Total Process Capital (sum of process areas)	$10,443	$41.8
(B) General Facilities (2% of A)	$209	$0.8
(C) Engineering (8% of A)	$835	$3.3
(D) Project Contingency (15% of A+B+C)	$1,723	$6.9
(E) Total Plant Cost (A+B+C+D)	$13,210	$52.8
(F) Allowance for Funds During Construction (1.91% of E)	$252	$1.0
(G) Total Plant Investment (E+F)	$13,463	$53.9
(H) Royalty Allowance (0% of A)	$0	$0.0
(I) Preproduction Cost (2 month startup)	$184	$0.7
(J) Inventory Capital	$130	$0.5
K) Initial Catalyst and Chemical	$0	$0.0
(L) Total Capital Requirements (G+H+I+J+K)	$13,777	$55.1

Exhibit M

Catalyst Price Sensitivity (@ $450/ft3)
250 MW Base Case SCR Operating and Maintenance Cost for 60% Removal

Fixed O&M Costs	Units	Quantity	$/Unit	$/ yr
Operating labor	Man-hr	2847	$23.00	$65,000
Maintenance labor				$84,000
Maintenance material				$125,000
Administration/support labor				$45,000
Subtotal Fixed Costs				$319,000

Variable Operating Costs	Units	Quantity	$/Unit	$/ yr
Fuels				
Coal	MBTU/hr	3.56	$2.00	$41,000
Sorbent				
n/a				$0
Chemicals/Catalyst				
Ammonia	lb/hr	187	$0.13	$133,000
Catalyst	cu. ft.	(Note 1)	**$450**	$506,000
Utilities				
Condensate	10^3 lb/hr			$0
Raw water	10^3 gal/hr			$0
Cooling water	10^3 gal/hr			$0
LP steam (0-70 psia)	10^3 lb/hr			$0
MP steam (70-250 psia)	10^3 lb/hr			$0
HP steam (>250 psia)	10^3 lb/hr			$0
Electric power	kWh/hr	639	$0.03	$109,000
Byproduct Credits				
n/a				$0
Waste Disposal Charges				
n/a				$0
Subtotal Variable Cost				$789,000
TOTAL O&M COSTS (FIXED + VARIABLE)				$1,108,000

Note 1 - Catalyst is not replaced on a yearly basis. Refer to catalyst management plan for addition and/or replacement schedule. Dollar amount shown in this table represents a levelized annual reserve for replacement based on present worth analysis of the catalyst replacement schedule.

Exhibit M

Catalyst Price Sensitivity (@ $450/ft3)
250 MW Base Case SCR Operating and Maintenance Cost for 60% Removal

Power Plant Attributes			Units	Value
Plant capacity, (net)			MWe	235
Power produced, (net)			10^6 kWh/yr	1338.09
Capacity factor			%	65
Plant life			years	30
Coal feed			tons/yr	540,930
Sulfur in coal			wt %	2.33
Emission Control Data			**Units**	**Value**
SCR removal efficiency			%	60
Emission without controls			lb/MBTU	0.35
Emission with controls			lb/MBTU	0.14
Amount removed			ton/yr	1374
	Current Dollars		**Constant Dollars**	
Levelized Cost, mills/kWhr	**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.150	1.544	0.116	1.194
Fixed O&M Cost	1.362	0.325	1.000	0.238
Variable O&M Cost	1.362	0.803	1.000	0.485
Total Cost		2.672		1.917
Levelized Cost, $/ton NOx Removed	**Factor**	**$/ton**	**Factor**	**$/ton**
Capital Charge	0.150	$1,504	0.116	$1,163
Fixed O&M Cost	1.362	$316	1.000	$232
Variable O&M Cost	1.362	$782	1.000	$472
Total Cost		$2,602		$1,867